ipaa
America's Oil & Gas Producers

BY U.P.S. OVERNIGHT

May 15, 1997

Mr. David S. Guzy
Chief, Rules and Procedures Staff
Minerals Management Service
Royalty Management Program
Building 85
Denver Federal Center
Denver, CO 80225

Re: Notice of Proposed Rulemaking, 62 Fed. Reg. 3742 (January 24, 1997)

Dear Mr. Guzy:

The Independent Petroleum Association of America ("IPAA") welcomes this opportunity to comment on the notice of proposed rulemaking the Minerals Management Service ("MMS") has issued regarding the value of the federal royalty on oil. The IPAA is a national trade association representing the nation's independent oil and gas producers. Collectively, its member companies produce a significant portion of all oil and gas from Federal lands. As independent producers, IPAA's 5,500 members see their interests best served by obtaining the highest possible price for the oil and natural gas they produce.

From the start, we want to be sure that our colleagues within the Department of the Interior understand the intent behind these comments. At several places, we discuss federal royalty law precedents to re-focus your attention on those fundamental first principles on which the federal royalty program is founded. Whether MMS meant to or not, it has departed from those principles in the proposed rule. If MMS does not return to them, it will not only unfairly increase certain lessees' royalty burdens, it will also significantly alter the practices on which our members' businesses are based. Nevertheless, we recognize MMS has committed to reduce its reliance on posted prices, and IPAA offers several recommendations to help MMS rationally achieve that goal until MMS is prepared to implement a complete royalty-in-kind program.

SUMMARY

The IPAA opposes the new MMS valuation scheme as proposed.

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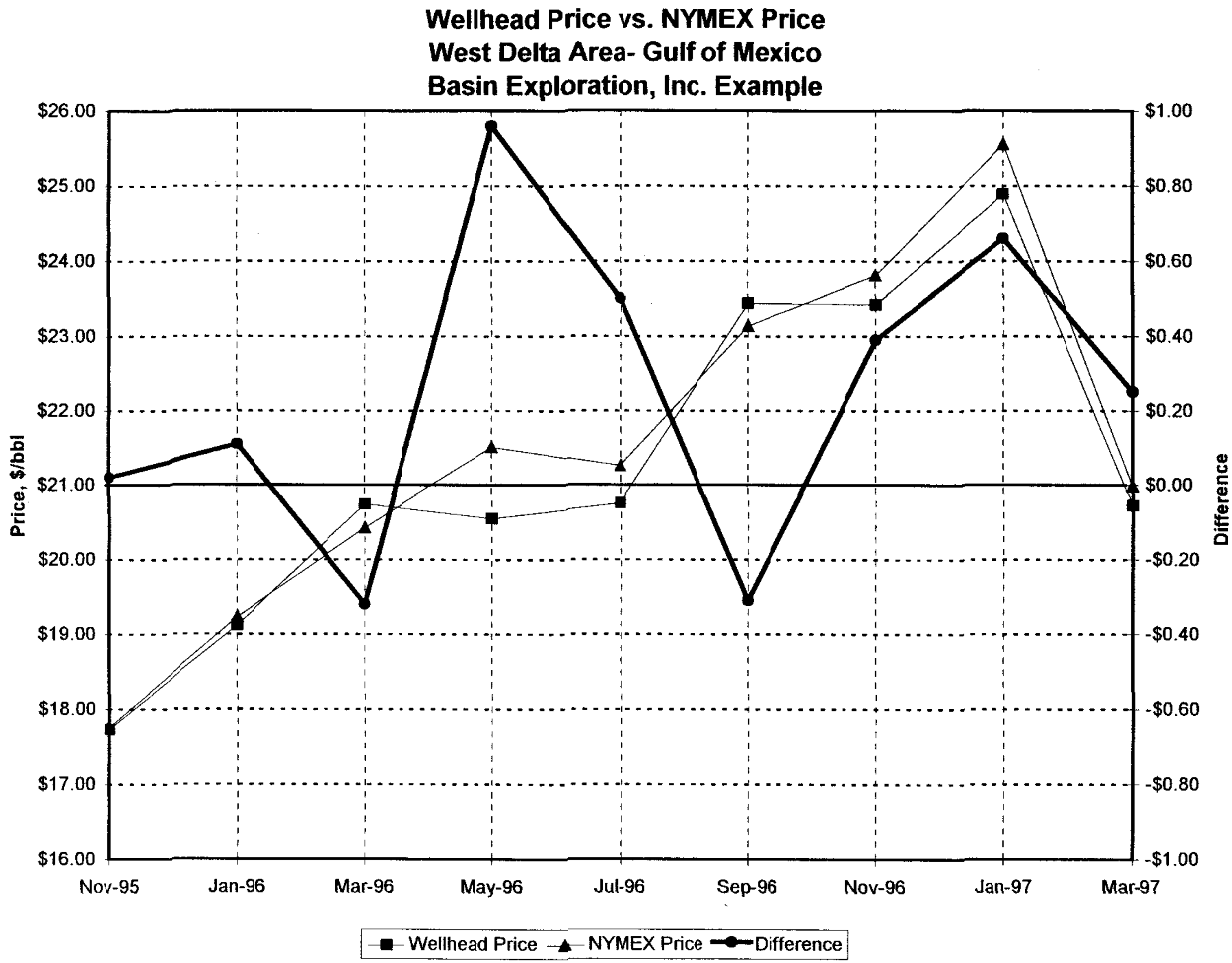
From the rulemaking record MMS has assembled so far and from its public statements, it is apparent that this proposed rule has grown out of MMS's decision to abandon reliance on posted prices as a basis for valuing royalties on a lessee's non-arm's-length sales of crude oil. MMS's advises that almost 70 percent of oil produced from federal leases is not sold at arm's length. While the volume of crude oil sold under non-arm's-length arrangements may be high, the number of companies selling under these arrangements constitute a small percentage of the number of companies which will be dramatically impacted if this rule is adopted.

The agency's stated goal is to "decrease reliance on oil posted prices" as a measure of market value. 62 Fed. Reg. 3742. But the result this proposal reaches is to eliminate reliance on market prices at or near the lease. It replaces the wellhead market price with an average NYMEX futures price, and then attempts to adjust for differences in location and quality to derive values at each of the thousands of producing wells in this country. As a simple illustration of our concern, one of our members, Basin Exploration, Inc., has tracked the prices it actually received for oil it sold from its Gulf of Mexico leases in the West Delta area against the NYMEX price MMS is proposing lessees use.

Production Mo.	Wellhead Price	NYMEX Price	Difference
Nov. 1995	$17.73	$17.75	.02
Jan. 1996	$19.12	$19.23	.13
Mar. 1996	$20.75	$20.43	-.32
May 1996	$20.55	$21.51	.96
July 1996	$20.76	$21.26	.50
Sept. 1996	$23.44	$23.13	-.31
Nov. 1996	$23.42	$23.81	.39
Jan. 1997	$24.89	$25.55	.66
Mar. 1997	$20.73	$20.98	.25

Would MMS's proposed adjustments for location and quality accurately reflect the differences between the NYMEX price for oil in Cushing, Oklahoma, and what Basin Exploration actually received hundreds of miles away in the Gulf of Mexico? Almost certainly not. The artificiality of MMS's proposed rule guarantees that there will be winners and losers. Some companies will pay royalties on less than they actually receive; some will pay more. Individual companies, like Basin Exploration in our example, will win or lose from one month to the next. But, as IPAA Vice President Ben Dillon testified at MMS's



Wellhead Price vs. NYMEX Price
West Delta Area- Gulf of Mexico
Basin Exploration, Inc. Example
Price, $/bbl
$26.00
$25.00
$24.00
$23.00
$22.00
$21.00
$20.00
$19.00
$18.00
$17.00
$16.00
Difference
$1.00
$0.80
$0.60
$0.40
$0.20
$0.00
-$0.20
-$0.40
-$0.60
-$0.80
-$1.00
Nov-95
Jan-96
Mar-96
May-96
Jul-96
Sep-96
Nov-96
Jan-97
Mar-97
Wellhead Price
NYMEX Price
Difference

public hearings, the odds are that independents, who have the least contact with the NYMEX market, are more likely to find themselves on the losing end.

Neither the rulemaking notice nor the related documentation from the rulemaking record (which MMS has released under the Freedom of Information Act) supports the need for this kind of an amendment to the current regulations. It appears from that record that MMS has adopted a set of assumptions about oil markets from consultants whose primary business is to aid the plaintiffs' bar in conducting litigation against producers of oil and natural gas. (Indeed, at least one of these consultants originally obtained contingency fee contracts of up to 50% from his clients.) These assumptions have not been tested by any empirical study and have not even been the subject of any peer-reviewed academic paper in the field of economics. They have, however, been preliminarily examined in litigation. In *Engwall v. Amerada Hess*, No. CV-95-322 (5th Jud. Dist. N. M.), the court refused to certify a class action proposed by plaintiff-lessors, based on the theory that valuation should begin with prices for oil traded in Cushing, Oklahoma, then adjusted back to leases in New Mexico. It did so because the "various claims asserted by plaintiffs ... are novel in the sense that plaintiffs have not cited to the Court previous precedent from any jurisdiction which has accepted plaintiffs' legal theories with regard to the royalty and overriding royalty obligation...." *Id.*, Decision at 2 (March 26, 1997). MMS has failed to lay the foundation for the dramatic change it seeks to impose.

IPAA has heard the assertion of Deputy Associate Director Donald Sant and Division Chief Debbie Tschudy that the results of MMS's own auditing program demonstrate the weaknesses of the current valuation system. Their opinion is based on their view that lessees are not attempting to document that their posted prices are in line with arm's-length transactions in the field involving significant quantities of crude oil. (Transcript of April 17, 1997, public hearing in Houston, Texas, pp. 46-47.) This opinion overlooks a fundamental point. MMS has not carried out its own duty, identified by the Interior Board of Land Appeals eight years ago, to make information from its own extensive data base about comparable arm's-length sales available for use under the benchmarks. *Mobil Oil Corp.*, 112 IBLA 56, 63-64 n.8 (1989), observed that "a lessee might run afoul of price-fixing restrictions if it attempted to assemble this data. On the other hand, MMS, which receives contract information from all Federal lessees, is in a much stronger position to assert ... a determination as to whether a particular contract price is permissible."

MMS will continue to have enforcement issues for as long as it takes royalty in value. If royalty in value remains MMS's preferred option, IPAA recommends significant changes in MMS's current benchmark system. There is, and has long been, an active market for crude oil at the lease level. Sales transactions occurring there offer the best evidence of the value of royalty oil at the lease. If it is not yet prepared fully to market its royalty share in kind, the Department should continue to treat arm's-length sales, as defined in the current rules, as it currently does: the royalty value is what the lessee receives under the sales contract.

For non-arm's-length sales, the Department should change its current benchmarks to eliminate any reference to posted prices.[1] The Department would rely instead on arm's-length transactions in the same field or area and on its own prices received from its sales of royalty in kind in that field. In any field or area in which no arm's-length sales are occurring, the Department should take its royalty in kind there. Monthly, for each field or area in which the Department is not taking its royalty in kind in full, the Department would publish information on prices received in prior arm's-length transactions. Alternatively, it could permit lessees to rely on arm's-length wellhead prices for similar crude oil reported in private publications as these publications extend their reporting to wellhead transactions. Either method or both would allow lessees selling in those fields under non-arm's-length arrangements (or moving the oil without sales) to have access to arm's-length pricing information. MMS would be assured of faster receipt of the correct value.

Ultimately, however, IPAA recommends that the Department of the Interior exercise its right on federal leases to take its royalty share in kind.

As owner of about three percent of domestic U.S. production, the Department would be, in effect, one of the largest producers of crude oil in the country. Using its market power, the Department could, if it chose to take the risks inherent in moving oil beyond the wellhead market, aggregate its volumes to obtain the rewards successful risk-takers obtain at downstream market centers. It could also dramatically shrink the size of the MMS's workforce, as well as that of lessee-producers. The need for auditors and legal staff to process administrative appeals would decline dramatically. The Clinton Administration could take justifiable pride in converting the agency into a lean, highly profitable enterprise promoting the public's fiscal interests. As a guidepost, the Department need only look to the royalty in kind program run by the Province of Alberta, Canada.

AN INTERIM RULE WOULD BE BAD PUBLIC POLICY

MMS stated in its notice that it would consider adopting this proposal as "an Interim Final Rule while it further evaluates the methodology in this proposed rule." 62 Fed. Reg. 3743. The alleged benefit of an interim rule would be to give MMS "the flexibility to do a revision after the first year without a new rulemaking." *Id.*

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[1] These comments will refer repeatedly to the use of benchmarks. When using the term, IPAA is not referring to MMS's proposed NYMEX-based valuation scheme. It is referring instead to information on arm's-length sales in the lease market in the given field or area. Under the benchmark system, a lessee would value its oil sold under a non-arm's-length contract using that contract's price, as long as that price was within the range of prices received under comparable arm's-length sales. If the lessee's price were below the range, it would be obliged to value the sale using the lowest comparable arm's-length price.

It is impossible to overstate IPAA's opposition to this idea. MMS has proposed to turn the current oil valuation rules inside out. Before this proposal was issued, IPAA discussed with MMS the importance of preserving the gross proceeds approach to valuation for America's independent producers. (See Exhibit 1.) And IPAA's conversations with MMS at the public hearings revealed that the MMS proposal had been more sweeping than you had realized. If MMS had not followed notice and comment procedures with the proposed rule, but in the name of "flexibility" had issued a final rule on January 24, then virtually all independent producers would now find themselves valuing oil using the NYMEX price. Now MMS wants the "flexibility" to effect still more changes a year later without any further opportunity for public comment.

IPAA thinks that position is unfair. The process of public comment is not a harness on the agency. It is an opportunity for the agency to learn and for the affected constituents to know their concerns have been heard and addressed. Without that opportunity, the agency could make further mistakes, and lessees would have to take their concerns and frustrations to the Congress and the courts. In a democracy, railroading radical change is never well-received.

In the meantime, MMS would impose costly alterations in the recordkeeping systems of federal leases to come into compliance with the interim rule -- alterations which may need to be undone or further altered when the agency changes its mind a year later, and perhaps altered again after litigation. Even without an interim rule, it is apparent that MMS has significantly underestimated the compliance costs of its proposed scheme. IPAA directs MMS's attention to the preliminary analysis of these costs which IPAA and other associations submitted to the Office of Management and Budget on March 25, 1997. (See Exhibit 2.) If MMS proceeds with an interim rule, it will only exacerbate that underestimate.

Ultimately, an interim rule would be the <u>most</u> inefficient option. MMS must follow notice and comment procedures when adopting or amending a rule. 30 U.S.C. § 1751(b). It is most unlikely that MMS could demonstrate that it had "good cause" to adopt revisions to the interim rule without following those procedures. *See* 5 U.S.C. § 553(b)(B); *Tennessee Gas Pipeline Co. v. FERC*, 969 F.2d 1141 (D.C. Cir. 1992). A successful lawsuit would create a third set of changes in lessees' data systems, after the court throws out the agency's revision.

IPAA was therefore heartened to read the Director's press release of April 21, 1997, indicating that the agency "may reopen the comment period" for "consideration of other options." That would be a positive response to the extensive comments and concerns raised by producers, and the Director has IPAA's support for that course of action.

<u>MMS's ASSUMPTIONS IN THE PROPOSED RULE; IPAA's CRITIQUE</u>

MMS's proposed rule is premised on several fundamentally false assumptions about crude oil markets. Because most of these assumptions are interrelated, it is somewhat artificial to separate them, but necessary to allow for adequate discussion.

1. **<u>MMS Wrongly Assumes There Is No Longer a Market for Crude Oil At or Near the Lease Which Can Be Used Reliably for Valuing Federal Royalty</u>**.

MMS's proposal at least still recognizes the concept of valuing production using information from the lease market, because it acknowledges "the presence of true arm's-length sales, especially by independent producers with no reciprocal purchases or trades...." 62 Fed. Reg. 3744. As to these sales, MMS says it will continue to accept the lessee's gross proceeds under the sales contract as the correct value for royalty purposes. Proposed 30 C.F.R. § 206.102(a).[2]

But MMS's proposal also asserts that most initial transactions are suspect, 62 Fed. Reg. 3744, suggesting the belief that the thousands of independent producers selling crude oil in this country have created a collusive market. This, of course, is the same market in which the MMS itself participates as a seller of crude oil from the lease. MMS takes more than one-third of its royalty on oil in kind and sells the oil itself. The prices it has received are the same prices which producers have received.

The proposed rule is so unmoored from the Department's longstanding approach to valuation that it is essential for MMS to recall what those moorings are. The Department of the Interior issues and administers oil and gas leases under the Outer Continental Shelf Lands Act, 43 U.S.C. §§ 1331 *et seq.*, the Mineral Leasing Act, 30 U.S.C. §§ 181 *et seq.*, and the Acquired Lands Leasing Act, 30 U.S.C. §§ 351 *et seq.* For the purpose of this rulemaking, the Department's authority under each is essentially the same. The Secretary is to issue leases while reserving a royalty of a given percentage of the amount or value of oil produced and removed or sold from the lease.

For royalty purposes, value "means 'reasonable market value'; that price which a product will bring in an open market, between a willing seller and a willing buyer." *United States v. General Petroleum Corp.*, 73 F. Supp. 225, 235 (S.D. Cal. 1947), *aff'd sub nom. Continental Oil Co. v. United States*, 184 F.2d 802 (9th Cir. 1950). *See also California Co.*

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[2] This statement is qualified by five exceptions, listed in proposed section 206.102(a)(2) through (6). As we will discuss below, three of these exceptions completely swallow the rule, wrongly placing all federal lessees into the NYMEX/ANS valuation scheme. For now it is enough to note that MMS -- at least in theory -- has not completely abandoned its historic reliance on valuation in the lease market.

v. Udall, 296 F.2d 384, 387 (D.C. Cir. 1961) ("value" under Mineral Leasing Act means "fair market value"). *Cf. NRDC v. Hodel*, 865 F.2d 288, 312 (D.C. Cir. 1988) (approving Secretary's "willing buyer and willing seller" test for fair market value in the sale of leases); *Amoco Production Co. v. Hodel*, 877 F.2d 1243, 1245 (5th Cir. 1989), *cert. denied*, 493 U.S. 1002 (1989) (applying this fair market value test to oil and gas royalties).

Under the leasing statutes, it has long been settled that volumes of production are measured and valued at the wellhead on the lease. *General Petroleum Corp.*, 73 F. Supp. at 254 ("royalties are payable on the gas as it is produced at the well"); *Mobil Producing Texas & New Mexico, Inc.*, 115 IBLA 164, 171 (1990) ("normally gas is sold and valued for royalty purposes at the wellhead"). Even the Department's most attenuated method of valuing royalty, which values certain natural gas from Alaska's Kenai Peninsula by starting with the first sale's price in Japan and netting out the costs of transportation and liquefaction, is nothing more than an attempt in a "special, unique situation" to "arrive at a reasonable wellhead value." *Marathon Oil Co. v. United States*, 604 F. Supp. 1375, 1385 (D. Alaska 1985), *aff'd*, 807 F.2d 759 (9th Cir. 1986), *cert. denied*, 480 U.S. 940 (1987). This measurement and valuation historically has occurred at the "point of royalty computation" located ordinarily "at the wellhead" or within the "lease ... boundary." (Conservation Division Manual, Part 647, chapter 1, p. 3.) Though the point of royalty computation is now called the "point of royalty settlement," 30 C.F.R. § 206.103(a)(1), its location remains unchanged. 43 C.F.R. § 3162.7-2 (onshore) and 30 C.F.R. § 250.180 (offshore).

Of course, it is not always possible for the producer to sell production at the lease. Whenever that situation arises, the Department values the royalty share by looking to the first sale of the production, then granting a reduction from that price for the cost of transporting it from the lease to the point of sale. But the Department's willingness to grant transportation allowances cannot obscure the fact that the Department has looked to the market nearest the lease as the proper place to begin royalty valuation. Although the Department grants transportation allowances "where there is no market in the field," *id.*, "transportation costs have been disallowed where the costs claimed were for transportation beyond the point of the nearest potential market." *ARCO Oil and Gas Co.*, 109 IBLA 34, 38 (1989). *Superior Oil Co.*, 12 IBLA 212 (1973), is the best known illustration of the principle. There the lessee sought an allowance to transport oil beyond the point of the first potential market, Burns Terminal in Louisiana. The Department denied an allowance transportation costs incurred beyond Burns. *See also Kerr-McGee Corp.*, 22 IBLA 124, 127-28 (1975) (approving allowance because lessee sought an allowance for transportation only to "the point of the first market," distinguishing *Superior Oil*). In sum, the Department has found in the past that the market nearest the lease provides the best information about the value of oil at the lease.[3]

[3] *Marathon* involved the unique situation where natural gas was not sold until after the lessee had liquefied it and shipped it by tanker to Japan. The point of first sale was in Tokyo. MMS declined to accept comparable values for gas sold in the field in Alaska's

That is certainly the approach Congress intended. The policy of Congress has been to create a federal lease consistent with "the terms of leases which have been developed and are in general use in the industry after a long period of trial and error...." H.R. Rep. No. 2078, 81st Cong., 2d Sess. 9-10 (1950) (OCS Lands Act). *See Amoco Production Co. v. Andrus*, 527 F. Supp. 790 (E.D. La. 1981) (rejecting agency interpretation of leasing statute as inconsistent with longstanding industry and agency practice); *Marathon Oil Co. v. Andrus*, 452 F. Supp. 548 (D. Wyo. 1978) (same). All states of which we are aware value royalty at the wellhead or on the lease. *See, e.g., Heritage Resources, Inc. v. Nationsbank*, 939 S.W.2d 118, 122 (Tex. 1996); *Babin v. First Energy Corp.*, 1997 WL 155022 (La. App. 1997); *Piney Woods Country Life School v. Shell Oil Co.*, 539 F. Supp. 957, 971 (S.D. Miss. 1982), *aff'd in relevant part*, 726 F.2d 225 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985); *Hurinenko v. Chevron U.S.A., Inc.*, 69 F.3d 283 (8th Cir. 1995) (applying North Dakota law); *Vedder Petroleum Corp. Ltd. v. Lambert Lands Co.*, 50 Cal. App.2d 102, 122 P.2d 600 (1942). Consistent with this approach, Congress expressly limited MMS's power to compel royalty recordkeeping to information through the later of "the point of first sale or point of royalty computation...." 30 U.S.C. § 1713(a).

Accordingly, until now, MMS has looked to prices received at the lease or in the field. Prior to the 1988 oil value rules, the agency looked to prices paid "in the field" and to "posted prices," which under industry practice were listings of prices buyers were offering to purchase crude oil at locations in the fields specified in the posting. 30 C.F.R. § 206.103 (1987). The 1988 rules, while more specific, reaffirm the policy of accepting the lessee's proceeds under arm's-length sales agreements, 30 C.F.R. § 206.102(b)(1)(i); and when the sales were not at arm's length, the lessee in almost all cases is to look to contemporaneous posted prices or oil sales contract prices used in arm's-length transactions in the same field. 30 C.F.R. § 206.102(c).

What has changed in the marketplace since 1988? There are more producing wells. A greater percentage of production from federal leases is owned by independent producers, especially from OCS leases. In 1996, the federal leases produced the greatest volume of oil in any of the last nine years, over 550 million barrels; and federal production as a percentage of national production reached its highest level for the period. (Exhibit 2 at

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Kenai Peninsula because those prices did not reflect the "gross proceeds" the lessee actually received from its first sale. In *Xeno* MMS rejected lease values because it claimed that a lessee's sales to its affiliate are not really sales at all, again relying on a new interpretation of the gross proceeds principle. Neither line of analysis in these cases provides the basis for the NYMEX scheme in this proposed rulemaking. MMS is not trying simply to determine the gross proceeds of a particular lessee's "true" first sale. It rejects essentially all first sale values as "suspect," 62 Fed. Reg. 3744, and instead imputes lease values by starting with the price of oil traded at Cushing, Oklahoma, or "market centers" in California, and makes a series of adjustments back to the lease.

4.) With more wells, more barrels, and more producers than before, it is not plausible to suggest that there is no longer a viable lease market.

In fact, the current lease market for federal lease oil is thriving. MMS knows this firsthand, for it sells a portion of its royalty oil at or near the lease, not at Cushing, Empire, or St. James. But the same is true of oil sold by lessees. IPAA asked its members to estimate what percent of their sales are at arm's length in the lease market. (By "lease market" we mean any first point of sale upstream of a market center, as MMS's proposal understands the market center concept.) Responses were in the 80 to 100 percent range. Smaller independents would likely fall in the high end of this range, the vast majority selling all their production at arm's length. Purchasers have told MMS the same thing. Jack Blomstrom of Eighty-eight Oil Company, a purchaser of federal crude oil, testified at the Denver hearing that his company buys the majority of its crude oil at the lease. (Exhibit 3.) And Scurlock Permian Corporation, a purchaser testifying in Houston, stated that it "and many other companies compete fiercely to purchase crude oil at the lease." Even the major integrated companies which presumably refine most of the oil they produce will have some arm's-length sales at the lease, including sales to small independent refiners under the 20 percent set-aside clause of OCS leases issued since 1978. *See* 43 U.S.C. § 1337(b)(7).

The rulemaking record MMS has assembled so far offers further proof of a flourishing lease market. Dr. Mike Harris of the Reed Consulting Group advised MMS that "[t]raditionally a large portion of sales are made at posted prices" by independent producers (presentation p. 7), indicating that the sales were in the field to which the posting applied. Another unidentified presentation stated that the "first point of sale for most domestic crude is at the lease," and that a "significant portion of activity is between [third] parties...." (Exhibit 4.) Sales at the lease are generally made under longer-term commitments, in contrast with sales at marketing centers where spot sales predominate to meet the short-term changes in the needs of refiners. *Id.* Even the presentation by Micronomics, Inc., one of the consultants supporting plaintiffs' attorneys in suits against producers, did not claim that information from the lease market was unreliable. It simply argued that the value of crude oil at the lease can also be determined in a different way, by using the method MMS adopted in the proposed rule. (Exhibit 5.) And the presentation by Summit Resource Management, Inc., another plaintiffs' consultant, explained that "independents commonly sell outright" and conceded that the proper value for "outright" arm's-length sales should continue to be the lessee's gross proceeds. (Exhibit 6.)

Implicit in MMS's view, however, is one of two assumptions: either most oil is first sold at arm's length in spot market transactions at market centers or that those spot market transaction nonetheless better reflect the value of all crude oil produced. These assumptions do not reflect a correct picture of the marketplace. Crude oil market centers are not like farmers' markets. They are not locations where producers take most of their oil for first sale or where refiners bring money to buy most of their supply. Instead, crude oil market centers serve as aggregation points for common streams of like-quality crude. A significant amount of crude oil that flows through a market center passes through without being involved in a sale there. The majority of market center sales are long-term arrangements. Spot transactions are entered into by refiners and resellers to balance supply/demand requirements.

Other things being equal, both refiners and producers prefer longer-term contracts. To the refiner, a longer term provides greater assurance that its minimum need for feedstocks will be met; to the producer, a longer term provides greater assurance that it will have regular income to pay its expenses. Thus, across the country, producers and refiners enter into agreements under which they buy and sell oil for a term which can span a few months to a number of years.

In sum, nothing supports MMS's proposed abandonment of values received from transactions at the wellhead or lease. All that MMS's documents reflect is that the further downstream one moves the crude oil, the more valuable that oil ordinarily becomes. But the higher price that the oil may receive reflects higher risks companies take when they move oil away from the lease and closer to market centers and refineries. These include risk of loss, risk of environmental liability, and risk of unfavorable price changes. The higher price typically also reflects the greater benefit one receives when aggregating large volumes of oil from many smaller wellhead streams. And the higher price reflects the additional cost incurred to move oil from the lease, to store it, to blend it, and to account for it once it is commingled with oil from other sources.

The difference between spot sales prices at market centers and longer-term sales prices at the lease is hardly evidence of a flaw in the lease market. The proposed rule's reliance on this difference as a basis for radical change is evidence of a flaw in the agency's analysis. Prices at the lease are the best measure of market value at the only point MMS may lawfully determine royalty value: the lease. The thriving lease market must remain the foundation for royalty value.

Recommendation: MMS's chief concern with the current rule, as that concern was explained to IPAA at the Houston hearing, is that it can be difficult to find "significant quantities" of oil sold at arm's length to use in the current benchmarks, especially given MMS's statement that 70 percent of federal oil is sold under non-arm's-length arrangements. IPAA does not have access to the data upon which MMS has reached this conclusion, but based on information in the public domain, we respectfully suggest that MMS has significantly overstated the concern.

MMS's concern over whether the quantities sold at arm's length are "significant" is a shorthand way of asking whether, in a given field, there are enough sales occurring for the agency to be confident that those sales represent market values. MMS has faced a similar problem in the past under its royalty-in-kind program. Under its rules for onshore production, refiners were charged the "market price:" the "highest price ... regularly posted ... by any principal purchaser in the field where produced...." 30 C.F.R. § 208.2(f) (1986). The State of California urged MMS to treat ARCO as a principal purchaser in the

Midway-Sunset field in California's San Joaquin Valley. MMS agreed, even though 71 percent of the oil from the field was sold under non-arm's-length contracts and even though ARCO's purchases at arm's length constituted less than 3.25 percent of all oil disposed of from that field. It is therefore not necessary for the volume of oil sold at arm's length to be large, though the agency might find that the smaller the total volume sold at arm's length, the greater the number of arm's length transactions should be to provide a reliable picture of market forces. IPAA would be pleased to work with MMS to develop appropriate criteria for interpreting market information under the new, improved benchmark system.

2. **The Proposed Rule Is Based on an Irrational Suspicion of Legitimate Arm's-Length Transactions.**

In 1988 the Department determined that it would continue to accept a lessee's proceeds under an arm's-length sales contract as "the best measure of market value." 53 Fed. Reg. 1186 (1988). The Department defined an arm's-length contract to mean one "arrived at in the market place between independent, nonaffiliated persons with opposing economic interests regarding that contract." 30 C.F.R. § 206.101. It placed no further restrictions on the use of arm's-length proceeds, absent a finding of unreasonable or bad faith behavior by the lessee when negotiating the contract. 30 C.F.R. § 206.102(b)(1)(ii) and (iii).

The Department's rationale for this policy was well-founded and straightforward.

> The MMS believes that the gross proceeds standard should be applied to arm's-length sales for several reasons. MMS typically accepts this value because it is well grounded in the realities of the marketplace where, in most cases, the <u>7/8ths or 5/6ths owner will be striving to obtain the highest attainable price</u> for the oil production for the benefit of itself; the <u>royalty owner benefits</u> from this incentive. It also adds <u>more certainty</u> to the valuation process for payors and provides them with a clear and equitable value on which to base royalties. Under the final regulations, in most instances the lessee will not need to be concerned that several years after the production has been sold MMS will establish royalty value in excess of the arm's-length contract proceeds, thereby imposing a <u>potential hardship</u> on the lessee.

53 Fed. Reg. 1198 (1988) (emphasis added).

The proposed rule retains one small piece of common ground with the current regulations. It would continue to honor "true arm's-length sales," 62 Fed. Reg. 3744, as the best indicator of the lease value of oil, and would use the lessee's gross proceeds from such a sale as the proper value for royalty. Obviously, IPAA supports this position. It relies on the market transaction closest to the lease. It recognizes that the lessee, as owner of the production, has at least as much incentive as the lessor (whose claim is only to a fraction of that production) to maximize income from the sale of the oil. And it requires the least amount of paperwork and accounting time for reporting, auditing, and enforcement.

The crucial problem with the proposed rule is that this gross proceeds approach to valuation becomes the exception, rather than the usual rule of valuation as it is under the current regulations. MMS is well aware of this, noting that it "expects that a relatively small volume of Federal oil production would be valued using the arm's-length gross proceeds method." 62 Fed. Reg. 3744. In fact, as Ben Dillon testified at the Houston hearing, the proposed rule is so restrictive that only an extremely small volume of oil will be valued under this approach: only one IPAA member polled believes his sales would be unaffected by the proposed rule. Read literally, the three limitations in the rule which restrict the use of the gross proceeds approach assure that no oil will qualify for gross proceeds treatment. These limits concern "crude oil calls," exchange agreements, and producers who also have purchased oil within the last two years. Each of these restrictions rests on false assumptions about the oil market.

a. The Purchase of Crude Oil Is Not a Suspect Transaction.

Under the proposal, a lessee may not rely on its gross proceeds if it, or any affiliated company, "purchased crude oil from an unaffiliated third party in the United States in the 2-year period preceding the production month." Proposed § 206.102(a)(6), 62 Fed. Reg. 3753. The restriction applies without regard to the purpose of the purchase. It applies whether or not the lessee is also selling other oil to the party from whom it has bought within the two prior years.

MMS would treat lessees which purchase oil as suspicious because of the mere possibility that the parties could manipulate the contract price.

> Just as with exchange agreements ..., a producer may have less incentive to capture full market value in its sales contracts if it knows it will have reciprocal dealings where it may be able to buy oil at less than market value. Several MMS consultants reinforced the notion that as long as the two parties maintain *relative* parity in value of oil production traded, the *absolute* contract price in any particular transaction has little meaning.

62 Fed. Reg. 3743.

IPAA finds no empirical data in the rulemaking record to support this assertion. Only one of the consultants (who makes a living as a plaintiffs' witness) discussed the problem of producers as purchasers. That consultant argued that some major oil companies follow an informal practice of keeping an "overall balance." That is, "as long as two companies sell approximately equal volumes to each other, the absolute price [in their various sales agreements] isn't important." But this consultant did not attempt to prove that any two major integrated companies actually have followed this practice, and he specifically disavowed that independents do so. (See exhibit 7.) Despite MMS's reference to "several ... consultants," this is the only one to have addressed the subject.

Under the proposed rule, any lessee who has bought oil from a third party within the last two years cannot rely on its proceeds under its arm's-length contracts, because of the possibility that the lessee has engaged in an elaborate sweetheart scheme with that party. But MMS apparently despairs of ever being able to detect such a scheme, because it does not simply single out lessees who buy volumes of crude oil equal to those they sell to the same party. Instead, MMS paints with the broadest brush, banning all purchasers of oil from using the gross proceeds approach. In so doing, MMS essentially eliminates the gross proceeds approach, for almost all producers purchase oil.

We start with MMS's unproven premise: that two companies can keep track of disconnected deals with each other to assure that they can mutually undervalue oil bought and sold and still remain in economic "overall balance." More concretely, the premise is that company A can buy California San Joaquin Valley heavy crude oil from company B, and sell Louisiana Light Sweet crude oil to company B in unrelated deals in different months over time, and manage to keep the volumes and the undervaluation of each oil in balance. That is a tall order. One must recognize that company A's need for San Joaquin Valley heavy oil is determined by market forces (supply of and demand for heavy crude oil in California) essentially unrelated to the market forces affecting its sale of Louisiana Light Sweet crude oil (supply of and demand for light, low-sulfur crude oil in the Gulf of Mexico region). To make this exercise worth the trouble, the two companies would have to agree to a significant undervaluation of each crude to see a real dividend in reduced royalties and taxes outweighing the increased administrative costs of such a scheme. And a significant undervaluation is easy to detect even in the most casual of MMS audits.

Almost all lessees buy oil, and do so for reasons completely unconnected to such schemes. Many operators of federal leases "buy" oil from the co-lessees under the terms of division orders or operating agreements to authorize the operator to sell the production from the lease or unit. Examples of these agreements and orders are found as Exhibits 8 through 10.

Widely used within the industry are the model forms approved by the American Association of Professional Landmen ("AAPL"). AAPL Form 610-1977 is the "Model Form Operating Agreement" which sets out the standard procedure for dealing with the problem of having multiple working interest owners with rights in a common stream of production from a given well. Under part VI. C. of the agreement, each working interest may take its proportionate share of the oil "in kind" and dispose of it; and every added expense from taking its share in kind is borne by that working interest alone. But any party who does not take its share in kind is subject to the right of the operator "to purchase such oil and gas or sell it to others at any time and from time to time, for the account of the non-taking party at the best price obtainable in the area...." (Exhibit 8 at 7.) The more recent AAPL Model Form Operating Agreements, Forms 610-1982 and 610-1989, continue the same procedure. (Exhibits 9 and 10.)

A similar procedure is standard in some forms for division orders. Simply because independent companies acting as operators use this standard procedure, they are thrown into MMS's alternative valuation scheme. Yet MMS has offered no evidence that their sales contracts have been the subject of manipulative dealing.

Other lessees sell their OCS oil production to a purchaser at arm's length at the lease; but they buy back 20 percent of the oil at an onshore location in order to deliver that oil to an MMS-designated small or independent refiner as required by the set-aside clause of their leases. (*See* 43 U.S.C. § 1337(b)(7).) Because the lessee has "purchased" oil, it would not qualify for use of the gross proceeds approach under the proposed rule. The only benefit to the lessee from selling the 20 percent set-aside volume at the lease and repurchasing it onshore is to transfer the risk of loss from the lessee to the first purchaser while the oil is in the offshore pipeline. MMS's royalty is not diminished in any way, and the lessee receives from the refiner nothing more than the lease price plus the cost of transportation.[4] An example of this kind of transaction is provided as Exhibit 11.

California lessees producing heavy crude oil often must buy light crude oil to blend so that the oil may be moved in unheated lines such as the All American Pipeline. MMS Director Quarterman has recognized this common practice in her memorandum to Assistant Secretary Armstrong on May 31, 1996, concerning the value of crude oil from the Elk Hills Naval Petroleum Reserve.

> Elk Hills oil is a higher quality crude (27-35 degrees API), which is more desirable for mixing with other crudes during transportation than the heavy crudes predominantly found in the San Joaquin Valley. This quality can avoid the need to access the few, more expensive heated pipelines available to transport heavy crude.

(See Exhibit 12.)

Finally, there is scarcely an independent producer who does not purchase crude oil for operations on the lease. For example, to improve the rate at which a given well will

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[4] The two-year restriction raises a separate concern. It is retroactive because it uses behavior occurring prior to the effective date of the rule (the purchase of oil) to alter the royalty consequences for lessees after the effective date of the rule. Even if MMS were to keep some restriction on the purchase of oil, it would be unlawful to have that restriction tied to conduct prior to the effective date of the rule.

flow and to increase the ultimate recovery of oil from that well, a producer may fracture the producing formation. The producer must consider several concerns in selecting the fracturing fluid, but crude oil or condensate is often the best fluid to address those concerns. Oil-based fracturing fluid systems are particularly useful in treating reservoirs that exhibit sensitivity to water and that require hydraulic fracturing treatments with proppant-laden fluid to become economically producing wells.

Nothing in these transactions suggests that the lessees are engaged in manipulation of their contract prices. MMS's would be arbitrary to prevent lessees which purchase oil from paying royalties on the gross proceeds from their arm's length sales.

Recommendation: At the April 17 hearing in Houston, MMS asked IPAA for comments to help it better address its concern about companies maintaining "overall balance." That "concern" -- for there is no proof that the problem exists -- is already addressed in current 30 C.F.R. § 206.102(b)(1)(iii): MMS may require an otherwise arm's-length sale to be examined under the benchmarks if the lessee's proceeds "do not reflect the reasonable value of the production because of misconduct by or between two contracting parties...." Few would disagree that two parties deliberately undervaluing their mutual sales and purchases to lower royalty and severance tax obligations are engaged in misconduct. But the restriction placed on lessees who have bought crude oil within the prior two years, proposed 30 C.F.R. § 206.102(a)(6), should not be adopted. IPAA can find no justification for any restriction, however crafted or fine-tuned, if it is tied to a lessee's purchase of crude oil.

b. The Restriction on Oil Subject to Crude Oil Calls Is Unfounded.

Under the proposal, a lessee may not pay royalties on its gross proceeds if the oil "is subject to crude oil calls." Proposed § 206.102(a)(4), 62 Fed. Reg. 3752. A "crude oil call" is defined to mean "the right of one person to buy, at its option, all or a part of the second person's oil production from an oil and gas property." Proposed § 206.101, 62 Fed. Reg. 3751. The definition appears to be intended to cover what others have named a "call on production," WILLIAMS & MEYERS, OIL AND GAS LAW § 427, an "option to purchase production," HEMINGWAY, LAW OF OIL AND GAS § 9.8 (3rd ed. 1991), a "preferential right and option," *Guidry v. Conoco, Inc.*, 1994 WL 518034 (E.D. La. 1994), or a "right of first refusal," *Cibro Petroleum Products v. Citgo Petroleum Corp.*, 602 F. Supp. 1520 (N.D.N.Y. 1985). The restriction is not limited to oil actually purchased by the owner of the call, but applies to oil subject to a call. It applies whether or not the price to be paid for the oil was negotiated at the same time the call was created.

Crude oil calls are contract based rights, ordinarily reserved by a prior owner of an oil property when conveying rights in the property to a purchaser, giving the prior owner the option of buying the crude oil produced. MMS's reason for this restriction is that the price negotiated at arm's length between the parties to the call is "suspect ... because the sale terms may be liberal to the property buyer in return for a favorable product purchase price by the property seller." 62 Fed. Reg. 3744.

The restriction on oil subject to a crude oil call is unwarranted and unworkable. At the outset, it is important to put this issue in perspective. The owner of the largest number of crude oil calls in the United States **is the United States!**[5] Everyone -- from Exxon to the smallest independent -- is subject to this call on their federal and Indian leases. Everyone is thus disqualified from using the gross proceeds approach. Yet experience indicates that the United States is motivated to maximize its income from the sale of the rights to the lease as well as from its royalty share. If this were not so, there would be no proposed rulemaking on which IPAA could offer these comments.

There is similarly no reason to suspect that a privately negotiated crude oil call would leave the call owner or the callee any less eager to maximize his income. Like the United States itself, private owners of rights in oil properties often wish to reserve the option of buying the oil produced from the lease when they grant their lease rights to a third party. Exhibit 13 is from a farmout agreement. There the farmor retained a "continuing option to purchase" the farmee's oil on 30 days' notice. The farmor is required to pay the farmee "the prevailing wellhead market price then being paid in the same field for production of the same or similar grade and gravity...." Exhibit 14 is an assignment with the assignor retaining the same right to the production on 30 days' notice and on payment of "the prevailing wellhead market price...." Exhibit 15 is a sale of the property with the seller retaining the same right upon payment of the same price. *See also Industria Sicilian Asfalti v. Exxon Research and Engineering Co.*, 1977 WL 1353 (S.D.N.Y. 1977) (discussing "right of first refusal at the prevailing market price"). In these cases the farmee, assignee, and buyer are going to obtain the best price the market will allow for that production if the other party exercises the call.

Calls on production retained by companies which issue posted price bulletins may use the particular company's posted price as the value to be paid for production. Exhibit 16 is an example of assignment from a major integrated company to an independent. The price to be paid "shall be Assignor's posted price...." However, if the assignee receives "a bona fide offer to purchase from an independent party" which beats the posted price, then the assignor must match that offer within 10 days or else its call is "temporarily waived." Exhibits 17 and 18 are essentially the same. Again, a sale under this kind of call raises no concerns about the producer's ability to obtain a fair price for royalty purposes.

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[5] The United States has the right to buy "at the market price" every barrel of oil a lessee produces on the Outer Continental Shelf. 43 U.S.C. § 1341(b). It claims a similar right with respect to Indian mineral leases. 25 C.F.R. § 211.11 (in time of public emergency, any federal agency may purchase all oil from a lease "at the posted market price") and § 212.17 (same right to purchase "at the highest posted market price"). Under section 30 of the Mineral Leasing Act, 30 U.S.C. § 187, each onshore federal lease provides that the Secretary may buy all or part of the production from the lease.

In the time permitted for comment, IPAA has been unable to conduct a comprehensive survey of the range of pricing provisions in crude oil calls. But the evidence in the rulemaking record regarding crude oils calls hardly warrants the cost of undertaking such an effort. Furthermore, there is absolutely no reason to suspect an arm's-length sale, even if subject to a call, when the call is not exercised. The fear that Crude Oil Call Owner A may have signed a sweetheart deal with Lessee B has no bearing on B's arm's-length sale to Buyer C. One independent with whom we discussed the issue reported that of 36 wells subject to a crude oil call, only on three had the call ever been exercised. There is also no reason to question oil sold under a call if the price was not negotiated at the time the call was created. *See Guidry v. Conoco, above* (oil taken under a call at the callor's posted price "or such other price as shall be agreed between" the parties). If the price the lessee has to pay to obtain the lease rights has already been set, the lessee has no incentive to give a less than market price to the owner of the call.

<u>Recommendation</u>: Perhaps the greatest difficulty for IPAA's members on the subject of crude calls is the cost of insuring compliance. Not every right of call appears in documents recorded in government title records. Some are created in documents that are merely referenced in record title documents. Compliance with the proposed rule would require renewed title examinations for each lease. That is an irrationally high price to pay when MMS's current rules already address the very slim risk of a manipulated sale price under a crude oil call. <u>See</u> 30 C.F.R. § 206.102(b)(1)(iii) (examine sale under benchmarks if proceeds are unreasonably low because of parties' misconduct). If MMS has concerns about a particular call, it can under current procedures require the lessee to show cause why its apparently unreasonably low sale should not be evaluated under the benchmarks. In sum, MMS should strike from proposed section 206.102(a)(4) any restriction based on crude oil calls.

MMS specifically asked for IPAA's views on whether MMS's concerns about crude oil calls could be addressed by a "bright-line" test. IPAA considered three options: exempting unexercised calls from the NYMEX scheme, exempting those as well as exercised calls with requirements for competitive pricing, and applying NYMEX only to exercised calls based on posted prices. The first two of these categories obviously need to be exempted from the NYMEX scheme. Nor is the third category inherently suspect, because many independents taking farmouts from major oil companies cannot negotiate a better price for the call than that major's posted price. The transaction is at arm's length and represents a fair value. Therefore, IPAA finds no basis for a "bright line" test, and it recommends instead a transaction-specific test of misconduct and unreasonably low prices under the call when exercised.

c. <u>The Restriction on All Exchange Agreements Is Unnecessary</u>.

Under the proposed rule, a lessee may not pay royalties on its gross proceeds if the oil is "disposed of under an exchange agreement...." Proposed § 206.102(a)(4), 62 Fed. Reg. 3752. An exchange agreement is defined to mean any agreement "where one person agrees to deliver oil to another person at a specified location in exchange for oil deliveries at another location." Proposed § 206.101, 62 Fed. Reg. 3751. The term includes buy/sell agreements in which a price is specified for the oil exchanged. The term is not limited to agreements in which the parties are trading an identical number of barrels. The term, however, does not include "'transportation' agreements, whose principal purpose is transportation." *Id.* MMS considers a transportation agreement to be one specifying "a location differential for moving oil from one point to the other with redelivery to the first party at the second exchange point." 62 Fed. Reg. 3744.

MMS regards exchange agreements as suspect because "the prices stated in an exchange agreement may not reflect actual value. For example, if the market value of oil were $20 per barrel (bbl), the two parties to the exchange each could price their oil at $18 bbl." *Id.*

MMS's approach to exchange agreements is difficult to justify. First, consider a simple barrel-for-barrel exchange with no price differential. Under such an exchange, neither party has set an express price, so there can be no manipulation of that price. The solution is to look at the nearest comparable wellhead transaction conducted at arm's length and apply that value to the exchange. That is the current practice, and in this context the fear of manipulation does not apply and cannot justify a change.

The fear of manipulation is only rational when the parties place a price in an arrangement like a buy/sell contract and use that price as the value of royalty. Arguably, two parties to such an exchange could agree to price oil that they otherwise would sell for $20 at only $15. But reality places significant constraints on a company's willingness to do this. For the undervaluation scheme to work for both parties, they would have to trade identical volumes of identical crude in a relatively short-term transaction; and each party would have to feel assured of the other's good faith and ability to honor the deal.

If the transaction were to last for more than, say, two months, the values of otherwise identical crudes could vary at different locations based on local shifts in supply and demand. The parties could not satisfy themselves that their relative positions would remain equal under the trade. If the crudes in the transactions were not of identical quality, then the parties would have to have detailed information about the "real" value of each crude so that they would know by how much to underprice each crude in the buy/sell agreement. Of course, through its very impressive data base, MMS has at least equal access (and probably superior access) to the information needed, so it could spot an undervalued exchange as quickly as the parties could arrange it. Finally, the volumes would have to be identical. For if one party was buying 400 barrels and selling 500 barrels at $15/bbl, then the other party is engaged in an outright purchase of 100 barrels at $15/bbl, $5/bbl below the $20 market price. The seller presumably is sufficiently motivated not to agree to such a discount. In fact, even if the volumes are identical, each party bears a risk that the other will not honor, or fully honor, the deal. If a breach or significant imbalance occurred, the victim's compensation would be limited to his own undervalued price.

MMS's consultant, Summit Resources, advised the agency that buy/sells are largely a transaction favored by major oil companies, not independents. (See exhibit 6.) Our own survey of IPAA members suggest that only a small percentage of their crude oil is involved in buy/sells, typically less than 25 percent. But it can be a useful transaction to market oil. It is therefore not reasonable for MMS to disregard all oil valued under exchange agreements (as that term is broadly defined); and in all events MMS has failed to justify why it cannot simply continue to compare the values used in exchanges with comparable arm's-length sales to set the proper value.

Finally, in many cases, there is no real distinction between a buy/sell agreement (which is treated as an exchange agreement) and a transportation agreement (which is not). In California, in particular, companies owning proprietary pipelines sometimes require the independent producer to enter a transportation agreement which looks exactly like what MMS's proposal calls a buy/sell. They do so because they believe that structuring the deal in that way is more persuasive evidence that they are truly moving their own production.

Recommendation: A lessee disposing of lease production under an exchange agreement which does not specify a price for the oils exchanged or under a non-arm's-length buy/sell agreement should value the oil under the improved benchmarks.

A more difficult question is presented by arm's-length buy/sell agreements. IPAA agrees with the principle that the "sale" component of an arm's-length buy/sell agreement needs to be within the range of comparable arm's-length sales in the field. It believes, based on the experience of its membership (as summarized above), that there are ample real-world safeguards to protect the lessor against price manipulation in a buy/sell. Accordingly, the soundest policy would be that oil disposed of under an arm's-length buy/sell agreement would be valued using the lessee's proceeds under the agreement, unless that value is unreasonably low because of misconduct by the parties. IPAA understands, however, the intensity of MMS's current distrust of buy/sell agreements; and IPAA believes it important that the public have confidence in how its officials address this perceived problem. Therefore, IPAA recommends that MMS give a lessee an option in valuing oil under an arm's-length buy/sell. The lessee may either use a price acceptable under the benchmark system, or it may use the price it receives from its subsequent arm's-length resale of the oil minus the differential, if any, between the price it sold for and the price it paid in the initial buy/sell. MMS could adopt appropriate restrictions limiting a lessee's ability to switch frequently from one method to the other.

d. MMS Must Not Shrink the Scope of the Current Gross Proceeds Approach

When MMS comprehensively examined royalty valuation for oil in the 1980s, it determined that it should continue to rely on transactions in the marketplace nearest the lease, particularly those entered into by persons with opposing economic interests.

> Value in these regulations generally is determined by prices set by individuals of opposing economic interests transacting business between themselves. Prices received for the sale of products from Federal and Indian leases pursuant to "arm's-length contracts," in many instances, are accepted as value for royalty purposes. However, even for some arm's-length contracts, contract prices may not be used for value purposes if the lease terms provide for other measures of value ... or when there is a reason to suspect the bona fide nature of a particular transaction. *Even the alternative valuation methods, however, are determined by reference to prices received by individuals buying or selling like-quality products in the same general area who have opposing economic interests.*

53 Fed. Reg. 1184, 1187 (1988) (emphasis added). The contrast between the current rule and the proposed rule is thus like that between night and day. The proposed rule presumes that all transactions in which there is the slightest possibility of a bad faith valuation are invalid indicators of market value. It then rejects reliance on any information from the lease market and uses a kind of netback approach to value oil, beginning with prices in Los Angeles, San Francisco, and Cushing, Oklahoma. The current rule, on the other hand, looks at a particular transaction and inquires whether it produces a value that is unreasonably low when compared with other comparable transactions at the wellhead in the same field. 30 C.F.R. § 206.102(b)(1)(iii) (1996).

We accept MMS's desire to change its approach to royalty valuation in light of the experience it has accumulated under the 1988 rules. But the rulemaking notice and the rulemaking record fail to refer to **any** evidence that MMS cannot assure compliance with the rules by auditing particular transactions for bad faith dealing. MMS has cited no evidence that oil subject to crude oil calls or exchange agreements is typically valued by the parties at prices lower than those obtained by parties selling comparable oil under arrangements that even MMS would concede are truly at arm's length. Indeed, if MMS has evidence of such undervaluation (as it apparently claims to have regarding oil produced in California and sold to affiliates), it presumably is enforcing the current regulation to assure that the proper value is being paid. As to arm's-length transactions, however, nothing in the record indicates that the current rules are in the least degree unworkable in dealing with possible undervaluation. MMS's accumulated experience offers no support for shrinking the class of transactions currently treated under the gross proceeds approach. Therefore, except for the treatment of arm's-length buy/sell agreements, IPAA urges MMS to retain its current policy on arm's-length transactions.

3. **<u>MMS Wrongly Assumes that Posted Prices Cannot Represent Market Prices</u>.**

Most crude oil today is still priced off of crude oil price bulletins, or "postings." While there may be an occasional wellhead contract using the NYMEX price as part of the pricing formula, the vast majority of pricing provisions in sales contracts remain postings-related. Companies which post prices use different strategies. Some treat their posting as their final price, others as a starting point in negotiations.

Accordingly, if MMS were to select 10 oil fields at random, and prepare a chart for 1995-96 plotting the arm's-length values on which federal lessees paid royalties against the posted price (or prices) for the fields, the chances are good that MMS would find a band of values in each field for each month. Some would be below the posted prices, as can be the case with low-gravity, sour crude oils in the Rocky Mountain regions, some would be at posted prices, some above the highest posted price. Many reasons could account for the differences, but the three most likely reasons would be that (1) different qualities of crude oils in different areas face different balances of supply and demand, (2) some sales would be under term contracts while others would be under spot contracts and (3) willing buyers and willing sellers negotiate different prices for essentially similar commodities. MMS readers of these comments will know the third point is true from their personal experience in buying homes and automobiles.

Looking at this imaginary chart -- which we would encourage MMS to actually construct from its extensive data base -- what could a reviewer infer about the fair market value of a given crude oil in a given field in a given month? A reviewer would correctly infer that all the prices under arm's-length contracts represent a fair market price. All were arrived at through free negotiations, and negotiated prices are what fair markets are all about.[6] As long as posted prices are within the band of such prices, they can be convenient measures of market value.

Most independents continue to receive posting-related prices at arm's length, as IPAA has confirmed by polling its membership. Furthermore, MMS's preamble to the proposal reveals that MMS <u>already knows</u> this to be true. It acknowledges that "many contract prices are tied to postings...." 62 Fed. Reg. 3744. If willing buyers and sellers are agreeing to use posted prices, then those prices reflect market value. Implicit in MMS's view that "mounting evidence" shows that posted prices "frequently" do not reflect market value, *id.*, is the correlative point that posted prices frequently still do reflect market value.

Prices are posted not only by integrated oil companies, but also by independent refiners and marketers such as Koch Oil, Scurlock Permian, and EOTT. Posted prices are

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[6] We assume MMS has not abandoned its longstanding view that fair market value does not mean the highest possible price. *See, e.g., NRDC v. Hodel*, 865 F.2d at 312.

used by buyers and sellers to negotiate absolute prices which may include an adjustment for gravity and/or a premium or deduction. Posting-based prices must be competitive and market responsive if a company is to be successful in purchasing crude. Market premiums are added to the posted price and paid to producers when a purchaser is willing to pay more than the gravity-adjusted posted price at the lease. Premiums vary in amount depending on location, volume, grade, type of crude, a the term of the supply commitment. Premiums are driven by competition and are negotiated on an arm's-length basis between producers and purchasers taking highly localized supply and demand factors into consideration and, thereby, defining the market values of lease crude in the field.

Recommendation: Postings-related prices still dominate the crude oil marketplace and remain an integral part of the process by which crude oil sellers and buyers transact business. Nevertheless, IPAA proposes that MMS eliminate all references to "posted prices" in its benchmarks. MMS has expressed publicly its commitment to change its system and has invested much effort in what is in effect lobbying members of Congress and committee staff for support of its desire to change. Its chief rationale for proposing this sweeping and radical revision is its belief that some lessees used their own posted prices to value crude oil when they actually were paying or receiving premiums over those postings. This perceived problem is most sensibly addressed by deleting the reference to "posted prices" from the benchmarks used to value oil when it is not sold at arm's length. And it is the subject of benchmarks to which we turn.

4. **MMS Wrongly Assumes It Is No Longer Feasible to Value Non-Arm's Length Sales by Comparing Them With Arm's-Length Sales.**

As we have already explained, the 1988 rules require that when oil is not sold under an arm's-length contract, the value for royalty is established by examining comparable arm's-length transactions in the lease market. This was no innovation. It reflected the culmination of years of case-by-case agency adjudication of royalty appeals.

The seminal decision in this area is *Getty Oil Co.*, 51 IBLA 47 (1980). There Getty entered into two agreements with Transcontinental Gas Pipe Line Corporation ("Transco"), one a sales contract, the other a transportation contract. Under the transportation contract, Transco agreed to ship a portion of the natural gas produced from Getty's offshore lease from the Gulf of Mexico to a connection near a refinery in Delaware. Getty sold the transported gas to its wholly owned subsidiary, which operated the refinery and which used the gas in a hydrocracking process. Under the sales agreement between Getty and its subsidiary, the subsidiary paid Getty the same price for the gas that Transco paid Getty under their sales contract.

The U.S. Geological Survey had assessed additional royalties against Getty on the theory that Getty could have abrogated its contract with its subsidiary at any time and sold the gas at a higher price. Rejecting this argument, IBLA ruled that "a parent corporation and its wholly owned subsidiary may enter into a valid contract." *Id.* at 50.

IBLA found it "error, in the absence of even a suggestion of impropriety, for GS to disregard the validity of Getty's agreement" with its subsidiary. *Id.* at 51.

> Although contracts between a parent corporation and its subsidiary may not be at arm's length, they may result in a fair market price. If a transaction is not at arm's length, some other manifestation that the price is nonetheless an accurate portrayal of the article's worth is required. It must be a price which independent buyers in arm's length transactions would be willing to pay.

Id. Since the price Getty received from Transco and from its subsidiary were equal, IBLA found that the subsidiary's price reflected the fair market value of the gas.

Although nothing in *Getty Oil* suggests that the rule should be different when the affiliated purchaser does re-sell the production, the facts in that case did not squarely present the issue. Subsequent IBLA decisions addressed this situation, however. In each one, IBLA compared the non-arm's-length sale with a sale by another producer to a first purchaser.

The first proof of this point came in a case concerning the valuation of royalties on zinc concentrates. *Amax Lead Company of Missouri*, 84 IBLA 102 (1984); *Amax Lead Company of Missouri (On Reconsideration)*, 99 IBLA 313 (1987). There the issue was how to value zinc sold under a non-arm's-length contract to a smelter in Illinois, which then processed the zinc for shipment and resale in markets on the Atlantic Seaboard. 84 IBLA at 103-04; 99 IBLA at 316. Both the MMS and the IBLA agreed that the value was to be determined by reference to prices received by unaffiliated producers of zinc who sold the concentrates to the Amax smelter.

The next case addressing *Getty Oil* in the context of the resale of oil or gas is one of IBLA's leading precedents in the area of royalty valuation, *Transco Exploration Co. & TXP Operating Co.*, 110 IBLA 282, 96 I.D. 367 (1989), *appeal filed* No. 90-191-L (Ct. Fed. Cl. Mar. 1, 1990) ("*Transco*"). In *Transco* the issue was whether Transco Exploration Company ("TXC") had correctly valued the royalty on gas it produced on lease OCS-G 1960 and sold to its affiliate, Transcontinental Gas Pipeline Corporation ("Transcontinental"), for resale in the interstate gas market. TXC over the course of three years routinely agreed to lower the sales price to Transcontinental. 110 IBLA at 285-300. IBLA agreed that MMS correctly had looked to see what other unaffiliated producers who held an interest in the same lease had sold the gas for. *Id.* at 336.

IBLA followed its *Transco* approach in *Ladd Petroleum Corp.*, 127 IBLA 163 (1993). There again royalty was valued at the price that an unaffiliated party had paid to purchase residue gas from the owner of the processing plant (whose proceeds the lessee shared in under a percentage-of-proceeds contract). *Id.* at 174. And in *Mobil Oil Corp.*, 112 IBLA 56 (1989), IBLA recognized the difficulty a lessee selling to an affiliate would have in obtaining the price data from its competitors in order to prove that its non-arm's-length contract had a price comparable to what parties would pay at arm's length. As a result, IBLA suggested that it would be easier for MMS to assemble that data from other producers.

> In effect, requiring a lessee to make such a showing comports with the option extended to lessees by the Board in *Getty Oil Co.*, 51 IBLA 47, 51 (1980), which held that the Department may value production for royalty computation purposes on the basis of prices derived from non-arm's-length transactions where such prices are reflective of the fair market value of the production. However, we note that a lessee could have difficulty in making a showing as to the validity of the price it used to value [natural gas liquid products] NGLP, as compared with other contract prices, since a lessee will not likely have complete information regarding all sales contracts in an area. In fact, a lessee might run afoul of price-fixing restrictions if it attempted to assemble this data. On the other hand, MMS, which receives contract information from all Federal lessees, is in a much stronger position to assert, and defend against challenge, a determination as to whether a particular contract price is permissible.

Id. at 63-64 n. 8 (emphasis added).

Recommendation: In keeping with our prior recommendation, IPAA urges MMS to significantly revise its current benchmarks to use measures from the lease market that MMS concedes are still reliable.

As its foremost step, MMS needs to recognize that when many independent parties with opposing economic interests come together in the marketplace to exchange a commodity, the resulting arm's-length negotiations will produce multiple prices for similar commodities. In other words, a properly functioning market will produce a range of fair market values *instead of a single fair market value. In revising its benchmarks, MMS needs* to recognize the range-of-value concept explicitly. If a lessee's non-arm's-length transaction is within the range of comparable ones at arm's length, the lessee's value should be accepted.

There are multitude of sales in the marketplace that even MMS's consultants would agree are at arm's length. At a minimum, for example, MMS should agree that a sale at the lease to a small, independent refiner is an arm's length sale. The refiner has every incentive to pay as little as possible, and the lessee has nothing to gain by selling at a below-market price. Similarly, a large class of independent producers would be regarded as arm's-length sellers even by the most suspicious MMS consultant. And if MMS continues to trust no other marketplace transaction at the lease, then surely MMS can trust itself. If MMS is reluctant to commit to a full RIK program, it should at least take RIK from every field where it distrusts the information from the lease market and should sell that oil competitively. With this information available, MMS is well positioned to employ benchmarks to test the values received under non-arm's-length arrangements.

The benchmarks could be arranged as follows.

- Privately-negotiated prices the lessee is receiving under other comparable arm's-length transactions in the same field or area. Included in this benchmark, for example, would be prices bid in response to a "tendering" program of the kind described by representatives of Conoco, Inc. at the Houston hearing. (See transcript pp. 89-94.)

- If the lessee has not received arm's-length proceeds for any comparable sale, arm's-length prices received by others in the field.

- If there are no comparable arm's-length sales in the given field, prices from nearby fields within an area acceptable to MMS.

- Prices received by MMS, adjusted to the lease, from its sales of royalty in kind from the field. These prices would be the net price MMS received after its agents deducted transportation costs and the marketing fee.

- A netback method appropriate to the particular lease. For example, where circumstances make it feasible, the netback might be to use index-based prices, adjusted back to the lease, using publicly reported cash trade prices negotiated at the nearest market center.

One difficulty with any benchmark system, of course, is assuring that lessees are aware of the benchmark prices. Antitrust laws place practical restrictions on what a lessee can research on its own. *See Mobil Oil Corp.*, 112 IBLA at 63-64 n.8. Monthly, for each field or area in which the Department is not taking its royalty in kind in full, the Department would publish information on prices received in prior arm's-length transactions. Alternatively, it could permit lessees to rely on arm's-length wellhead prices for similar crude oil reported in private publications as these publications extend their reporting to wellhead transactions. Either method or both would allow lessees selling in those fields under non-arm's-length arrangements (or moving the oil without sales) to have access to arm's-length pricing information. MMS would be assured of faster receipt of the correct value.

IPAA recognizes that MMS and lessees will have separate concerns about the manner in which this proposal for price publication would be implemented. The need to publish the information promptly may pose a challenge for the agency's AFS system. If the agency were to repropose a rule with this feature, IPAA would be ready to work with MMS during the comment period to address those concerns.

5. **<u>MMS Wrongly Assumes That Federal Lessees Have a Duty to Bear All Marketing Expenses at No Cost to the Lessor</u>.**

MMS proposes to adopt a section 206.102(e). That subsection would state that a lessee has a duty to place production in marketable condition, 62 Fed. Reg. 3753, meaning that the oil is "sufficiently free from impurities and otherwise in a condition a purchaser will accept under a sales contract typical for the field or area." 62 Fed. Reg. 3752. To this, however, MMS proposes to add a duty that the lessee must "market the oil for the mutual benefit of the lessee and the lessor at no cost to the Federal Government." *Id.* at 3753.

IPAA strongly objects to this newly-minted "duty to market." Although we have numerous reasons for this objection, the easiest to grasp is plain from the very language of the proposal. MMS calls this a duty to market for the **mutual** benefit of the lessee and lessor, yet it states it will not share mutually in the costs. It is, in short, a duty to market for the special benefit of the lessor and to the detriment of the lessee. There is no logic behind such a duty. It is nothing less than an effort to legislate through rulemaking.

Nor is the law behind such a duty. For federal leases, no duty to market without cost to the lessor can be implied, because the reason behind the implication of duties in an oil and gas lease is not present. The typical oil and gas lease is "silent about the obligation of the lessee with respect to the conduct of operations after oil or gas is first discovered." 5 H. Williams and C. Meyers, OIL AND GAS LAW § 801 (1985) (hereafter "OIL AND GAS LAW").

> The subject was, therefore, rationally left to the implication, necessarily arising in the absence of express stipulation, that further prosecution of the work [of development and production] should be along such lines as would be reasonably calculated to effectuate the controlling intention of the parties as manifested in the lease, which was to make the extraction of oil and gas from the premises of mutual advantage and profit.

Brewster v. Lanyon Zinc Co., 140 F. 801, 811 (8th Cir. 1905). The customary logic behind an implied duty to market is that without marketing of the production, there will be no production or revenue on which the lessor can claim royalty; and the promise of royalties "was the controlling inducement to the grant" of the lease. *Id.* at 809.

But MMS's quarrel here is not with a lessee's unwillingness to produce oil from a lease. It is instead with the value at which the lessee will pay royalties on oil it produces. And concerning the value of royalties, there is no room left between the lines of the leases and regulations for an implied duty to dwell. The Department has at all times had the option of taking the oil in kind and marketing it, and has routinely done so. For most leases, it also has held the power, after notice and hearing, prospectively to set reasonable minimum values for the royalty on production. It has determined through regulations what the value of royalty would be and incorporated those regulations into the text of the lease forms it drafted. And it has expressly dealt in its regulations with the duty to place production in marketable condition. Therefore, it cannot be said that the parties to these OCS leases intended the question of how marketing production is to affect the value of royalty to be governed by an implied generalized standard of reasonableness.

Furthermore, the Department's right and ability to take oil in kind are sufficient in themselves to prevent the creation of an implied duty to market. "If the lessor's share of the oil, under the royalty provisions of the lease, is deliverable in kind to the lessor, the oil is theoretically under the control of the lessor and arguably he should be the one to market it, not the lessee." OIL AND GAS LAW § 853. The Department cannot imply a duty to serve the same purpose and achieve the same result as a duty already expressed. The lease expressly creates a duty in the lessee to provide the royalty on oil in kind, and MMS may market that share to its maximum advantage. The lessee, of course, is not responsible for MMS's costs of marketing in that setting. So the lease cannot contain an implied promise for the lessee to pay those costs when the Secretary takes his royalty share in value.

As MMS knows, there is also no express duty to market oil without cost to the lessor in federal leases. Nor has such a duty been incorporated into leases by regulations in existence when the leases were issued. The first rule remotely to address the subject of marketing was issued in 1936 to govern onshore leases. 1 Fed. Reg. 1996, 1999 (1936). In relevant part it stated that the "production of oil and gas ... shall be limited by the market demand for gas or by the market demand for oil." 30 C.F.R. § 221.27 (1938). In other words, the Department expressly imposed on lessees a duty not to market in order to prop up prices.

In 1942, section 221.27 was amended and redesignated as 30 C.F.R. § 221.35. 7 Fed. Reg. 4132 (1942). As amended, the rule required lessees to adopt one of three alternatives to "avoid physical waste of gas": the lessee could "consume it beneficially...," could "return it to the productive formation...," or could "market it...." 30 C.F.R. § 221.35 (1943). The obligation to market natural gas did not state that it was without cost to the lessor. Additionally, the rule continued the duty not to market from the 1936 rule. The duty not to market remained in force until repealed in 1982. 47 Fed. Reg. 47758 (1982) (amending § 221.35 and redesignating as § 221.102). The duty to market (as one option to prevent waste) remained in force, 48 Fed. Reg. 35639 (1983) (redesignating it as § 206.100), until repealed in 1987. 52 Fed. Reg. 3796, 3798 (1987) (amending § 206.100).

OCS leases never were subject to an express duty to market. Leases issued in 1954 and later were subject only to an express duty to "put into marketable condition, if commercially feasible, all products from the leased land and pay royalty thereon without recourse to the lessor for deductions on account of cost of treatment." 30 C.F.R. § 250.41(b) (1956).

In sum, onshore federal leases issued between 1942 and 1987 are subject to a duty to market as one option to prevent waste of gas. Other federal leases are subject only to a duty to place oil in marketable condition. No federal lease is subject to an express duty to market oil, let alone to market it without cost to the lessor. IPAA realizes that MMS's position is that the law is "well settled that marketing expenses necessary to market production from a Federal lease must be performed at no cost to the lessor." *Amoco Production Co.*, MMS-92-0552-OCS at 4 (1996) (citing *California Co. v. Udall*, 296 F.2d 384, 388 (D.C. Cir. 1961)). As we have just shown, that position is patently false with respect to crude oil. But even as to natural gas the precedents indicate that the more principled view is the one that is more favorable to lessees.

California Co. concerned a federal lease in Louisiana's Romere Pass field. Calco sold natural gas at a point within the field to a pipeline for 12 cents per mcf, after Calco had removed excess water vapor and compressed the gas to a specified minimum. For royalty purposes, Calco wished to deduct 5 cents per mcf from the 12 cents received to reflect its costs of dehydrating and compressing the gas. The Secretary disagreed, arguing that Calco was obliged to bear that expense alone. To the court the question concerned the meaning of the statutory phrase "value of production."

> Does it mean the raw product as it comes from the well, no matter what its condition? Or does it mean that product readied for the market in and to which it is being sold?

296 F.2d at 387. The court observed that the lessee had an express duty under BLM's rules to "market" natural gas in order to avoid the "physical waste" of the production. Specifically, BLM required the lessee "to prevent the waste of oil or gas and to avoid physical waste of gas the lessee shall consume it beneficially or market it or return it to the productive formation." 30 C.F.R. § 221.35 (1959). Part of that duty to market the gas included the duty to put the gas in a condition acceptable to the "market, an established demand for an identified product." 296 F.2d at 388. "The only market, as far as this record shows, was for this gas at certain pressure and certain minimum water and hydrocarbon content." *Id.* While the court took care to explain that this case involved neither transportation nor manufacturing costs, *id.* at 387, *California Co.* firmly established the principle that a lessee subject to the terms of former section 221.35 had the duty to place natural gas in marketable condition.

Yet there is no bridge from that rather modest proposition to the proposed duty to market contained in the January 24 notice. The preamble to the proposal relies on *Walter Oil and Gas Corp.*, 111 IBLA 260 (1989), for its duty to market language. 62 Fed. Reg. 3746. There the lessee sought a deduction for the fee it paid an independent marketer to locate buyers, negotiate contracts, and monitor sales of gas produced from an OCS lease.

IBLA upheld MMS's position, reasoning that Walter's purchasers were "willing to pay the contract price for the gas, and this price included the fees Walter paid to Commet [the marketer] for its services." 111 IBLA at 264. So, under the gross proceeds rule, IBLA found the fees for Commet's services to part of the total consideration accruing to Walter.

> The only allowances recognized as proper deductions in determining royalty value are transportation allowances for the cost of transporting production from the leasehold to the first available market.... A lessee may choose to employ its own personnel to find markets for its gas, or it may decide to hire an independent marketer to perform these functions. The lessee's business decision as to which method it prefers does not affect the value of the gas for royalty purposes.

Id.

MMS reads too much into cases such as *Walter*. If the "duty to market" requires the lessee to bear at its sole expense all costs of marketing to sell oil in an established market, then the duty would also require a lessee to bear alone the expense of moving the production to an established market. In other words, if *California Co.* really were the basis of a general duty to market in the manner proposed, there is no principled basis to distinguish transportation from any other act needed to sell the oil. Yet the Department has conceded at least since *Shell Oil Co.*, 70 I.D. 393 (1963), that transportation costs need to be deducted from the proceeds of sale.

IBLA has attempted to explain the distinction, and its explanation undercuts the proposed rule. In *ARCO Oil & Gas Co.*, 112 IBLA 8 (1989), IBLA rejected the analogy between deductions for transportation and those for other marketing expenses.

> The analogy sought to be drawn ... is unpersuasive, because it fails to draw upon similar circumstances. . . . But for the fact that the only market was onshore at a point distant from the lease, the transportation costs ... would not have been incurred by the lessee. . . . No allowance will be recognized by the Department where a lessee, as here, would have borne similar costs attributable to the creation and development of markets regardless whether production was sold on or adjacent to the lease.

Id. at 10-11. In sum, even if a duty to market based on *California Co.* applied to oil, it would require a lessee to bear at its sole expense only those costs that it would otherwise have incurred if it had sold the production at the lease. Beyond that, the lessor is not entitled to share in the rewards (or losses) from those expenses and risks unique to downstream activities.

In the context of the proposed rule, the alleged duty to market raises special concerns for independent producers.

- First, because the proposal would value almost all independents' oil using NYMEX pricing, there is a serious risk that the duty to market would be used to justify MMS's claiming -- free of risk and cost -- the benefits of storage, blending, aggregation, and the like which result from downstream activities. Because almost all independents sell in the lease market, the proposed duty to market is nothing more than an unauthorized increase in the effective royalty rate under the lease. The lessee will be required to pay royalties on phantom proceeds.

- Second, until recently, it was the Department's policy to treat transactions between affiliates in a manner leaving them, to coin a phrase, in royalty parity with unaffiliated transactions. Now, however, MMS views transactions between affiliates as attempts to evade royalty obligations. One reason IPAA supports the expansion of royalty in kind is that it would give the agency an education in the marketplace on the role played by companies acting in the midstream of commerce -- between the lease on one end and the market center or refinery on the other.

Midstream companies are typified by independent marketers such as Scurlock Permian Corporation, which testified at the April 17 hearing in Houston. Scurlock competes with other marketers and with refiners to purchase crude oil in the field. It moves the oil through trucks, gathering lines, and pipelines to market centers. It maintains an inventory of stored crude oil at various locations around the country. That inventory enables it to enter exchanges, which often are more efficient means of "repositioning" crude oil than actual transportation of it would be. This aggregation of oil in inventories does not just permit more efficient movement of oil from a given lease to its ultimate destination, it also helps create a market for low-volume wells, such as stripper wells. Most refiners have no interest, because of high transaction costs, in seeking out producers who can offer less than 10 barrels per day from a well. To a refiner, the value of such oil may be several dollars a barrel less than it would pay for oil of similar quality from a more prolific field. Marketers like Scurlock aggregate these small volumes into "packages" of a size that will attract more competitive purchasing.

Midstream companies perform a variety of services and bear a variety of risks once the oil moves beyond the lease meter.

- Transportation
    - Contracting for or Providing Transportation
    - Scheduling of Volumes
    - Providing Pipeline Fill
    - Tracking Volumes Delivered
    - Providing Credit Services

- Storage
  - Constructing or Leasing Storage Facilities
  - Scheduling Storage Volumes
  - Maintaining Inventory

- Risk Management
  - Dealing with Price Fluctuations at or Upstream of Market Centers
  - Risk of Loss of Pipeline Volumes
  - Environmental Liabilities for Spills
  - Risk of Purchasers' Default

- Marketing
  - Aggregating Volumes
  - Satisfying Specialized Customer Quality Preferences

An illustration will capture how some of these risks play out in the real marketplace. The transport of oil from the lease to a market center may take days. During that time, a refinery to whom the midstream marketer was shipping the oil may experience an event of *force majeure*. Shut down and without adequate storage, the refinery could refuse to accept delivery without penalty or breach of contract. During the time of transit, the price of oil at the nearest market center may have dropped. Having bought high, the marketer would then have to sell low and assume the loss. No marketer could stay in business long unless its midstream activities generally resulted in profits that more than offset such losses.

The services and risks undertaken in the midstream market obviously add value to the oil beyond its value at the lease. Equally obviously, midstream services and risk assumption add value to the oil beyond its lease value plus the actual cost of transportation to the refinery or market center, because transportation is just one of the costs and risks involved.

The Department currently undertakes midstream risks when it takes its royalty in kind. The Department manages these risks by assigning them to the refiner under the royalty-in-kind sales contract. That is why the Department only receives the lease value when it sells the oil. But the Department relieves the lessee of these risks nonetheless. The new duty to market is simply MMS's effort to unilaterally compel lessees to assume these risks beyond the lease market when MMS takes its royalty in value. As IBLA has held in a similar context, it "would be an anomalous result if the Government royalty interest was, in effect, chargeable with transportation when taken in kind, but not when taken in value." *Kerr-McGee Corp.*, 22 IBLA 124, 128 (1975). So, too, MMS cannot refuse to charge the federal royalty interest with the risks and costs of the midstream market when taking royalty in value, when it must accept those risks when taking royalty in kind.

The result cannot be different simply because a producer creates an affiliate to participate in the midstream market. IPAA member affiliates in that market compete with independent marketers like Scurlock to purchase oil from unaffiliated producers as well as from their affiliated producer. They provide the same midstream services, expend the same costs, and assume the same risks. They add value to the lease value in precisely the same way. America's free enterprise system discourages artificial barriers and disincentives to independent producers wishing to enter into any legitimate line of business. It cannot be different for producers wishing to enter into midstream marketing. It is arbitrary for MMS to create disincentives by treating the lease value of oil from a given well differently simply because it is purchased by an affiliate instead of an independent marketer.

Recommendation: MMS cannot use any index-based price using a downstream index without deducting a value reflecting the expenses and risks of downstream activities. Simply deducting for transportation costs and adjusting for quality differences essentially gives MMS a cost-free, risk-free ride on the backs of companies engaged in downstream activities. There is no duty to market to support that result. MMS must strike the provision concerning the duty to market for the mutual benefit of lessee and lessor from the text of the proposed rule.

MMS Rationale for Use of NYMEX and ANS Prices

Citing "mounting evidence that posted prices frequently do not reflect value in today's marketplace," 62 Fed. Reg. 3744, MMS proposes to rely instead on the monthly "average of the daily NYMEX futures settle prices for the Domestic Sweet Crude Oil contract for the prompt month," *id.* at 3745, for oil to be delivered at facilities in Cushing, Oklahoma. If the lease in question is in California or Alaska, however, MMS proposes to rely on "the daily mean Alaska North Slope (ANS) spot prices for the month of production published in an MMS-approved publication...." Proposed § 206.102(c)(2)(ii), 62 Fed. Reg. 3753. Either average price would be adjusted "for applicable location and quality differentials" to approximate the value of the lessee's oil at the lease. Proposed § 206.102(c)(2)(i) and (ii), 62 Fed. Reg. 3753.

MMS believes that the NYMEX price is the superior measure of crude oil value. It resorts to the ANS spot price for Alaska and California simply because their "distance from the mid-continent markets would lead to great difficulties in making meaningful adjustments from the NYMEX price." Accordingly, "MMS believes that a more localized market indicator would better represent royalty value." 62 Fed. Reg. 3745. Even east of the Rockies, MMS concedes that reliance on NYMEX will involve "difficult location and quality adjustments." *Id.* Even so, MMS would adopt the NYMEX price as the nationwide standard because it "represents the price for a widely traded domestic crude oil (West Texas Intermediate at Cushing, Oklahoma), and there is little likelihood that any particular participant in NYMEX trading could impact the price." *Id.* More significantly, "MMS believes that today's oil marketing is driven largely by the NYMEX market." *Id.* at 3746.

To be sure, there is a close correlation among the NYMEX price, spot market prices for oil at market centers, and posted prices for crude oil sold in the lease market. MMS need only track Koch Oil's posted prices against spot prices and the NYMEX for a few months to see how closely the three move together. That correlation is the hard reality of today's oil marketing. From that reality, one can draw either of two conclusions: first, that NYMEX "drives" oil marketing or, second, that today's posted prices are highly responsive to changes in the marketplace. The first conclusion would seem to support MMS's desire to use NYMEX prices, the second would undercut MMS's rejection of postings-related prices. The problem with comparing these conclusions is that they deal with different levels in the continuum of commerce in crude oil.

If the oil in question is crude oil in storage tanks in Cushing, Oklahoma, it may be entirely appropriate to say that NYMEX drives the marketing of that oil. MMS's proper concern, however, is not with oil in Cushing, but with oil at the lease. And there, with respect, IPAA suggests that believing that the NYMEX market "drives" today's oil marketing is like believing that the cart drives the horse. The price that a willing buyer and a willing seller will agree to pay for crude oil at the wellhead is "driven largely" by the local supply of comparable quantities of crude oil and the demand for them. That supply and demand varies over time, sometimes subtly, sometimes dramatically.

This is not to say that the lease market and NYMEX are unrelated completely. On the contrary, over time the prices for oil in these different markets will show a correlation, as we indicated above. They should, for that is the point of having a futures market in oil. The NYMEX market exists to ameliorate the risks that producers and buyers of crude face when making operational and marketing decisions that depend upon the future price of crude oil. Indeed, the basic purpose of any futures trading is the transfer of risk from producers and users of a commodity to speculators. The futures market for oil creates a central, standardized forum in which such futures contracts can be bought and sold, with the risk of price changes being assigned and reassigned repeatedly and widely. The transfer of risk in this manner will tend to cause prices in the different markets to move up and down together over time.

But the real issue is whether the NYMEX price is a workable proxy for the price of oil at the lease. The actual commodity traded in the NYMEX is a contract right to future wet barrels, so-called "paper" barrels. There is, of course, ultimately a link in the price of wet and paper barrels, for occasionally a futures trader holding a contract actually has to either accept or provide delivery of real barrels of oil. Usually, however, the trader exits the market by taking an offsetting position, that is, removing an obligation to deliver barrels by obtaining an equal obligation to buy barrels in the same month, and taking his profit or loss in cash. This makes the two markets distinct enough to keep the NYMEX price removed from the reality of the market at the lease in the month of actual production.[7]

IPAA's concern is highlighted by the data provided MMS by the NYMEX in its presentation. For the third quarter of 1996, producers and buyers of oil, the persons actually hedging their risks in the cash market, comprise only 60 percent of the positions held in the futures market. Of these, producers account for only three percent. (Exhibit 19.) The remaining positions are held by entities that NYMEX describes as "speculators," "funds," and "financial." Such a wide participation is helpful to the hedgers, of course, for it makes the futures market very "liquid" and easy to enter and exit. But such heavy participation by persons not directly involved in the production and purchase of crude oil underscores the differences between the cash market for wet barrels and the futures market for paper barrels. The motivations of these persons differ from those producing and buying real barrels. A recent analysis in the *Oil and Gas Journal* underscored the difference.

> For example, assume that on a given day an extremely large speculator decides to go short. His brokers will then attempt to purchase 5,000 short contracts. All other things being equal, news of such a large increase in the number of shorts demanded drives down the price. The order for 5,000 short contracts amounts to a search for 5,000 long contracts, and in the open outcry process on the floor of the Nymex, the bid price will fall until the necessary number of longs are attracted to take the offsetting positions for the 5,000 shorts.
>
> This process can, of course, feed on itself. If the intra-day price decline forces prices below a support level, other bears will be attracted into the market, creating further downward price pressure. Fundamentalists in the physical market can only watch and wonder what led to the price decline since nothing of consequence was indicated in the physical supply/demand

[7] *MMS's proposal illustrates the problem.* To value production in September 1996, MMS would use the NYMEX price generated in trading between August 21 and September 20 for oil to be delivered in October 1996. 62 Fed. Reg. 3745. MMS recognizes that what NYMEX is trading during that period is not September oil. But it justifies this approach by observing that "[a]lthough it is a futures price, it would reflect the market's assessment of value during the production month." *Id.* This view is not well-considered. During the period of August 21 to September 20, NYMEX is trading not only contracts for October delivery, it is also trading contracts for delivery in any of the subsequent 30 months. All of this trading reflects in some sense "the market's assessment of value during the production month," but **none** of this trading reflects the market's assessment of the value of oil **delivered** in September 1996.

> equation. In truth, the initial decision on the part of the speculator to go short in the oil market may have had more to do with changes in the Nikkei or in other commodities than with anything happening in oil.

E.N. Krapels, "Why Energy Futures Markets Merit Support Amid Latest Controversy," *Oil and Gas Journal* 21, 23 (Feb. 10, 1997).

The NYMEX price is determined in a market that is largely insulated from the risks facing parties in the lease market for crude oil. As the NYMEX briefed you in October 1996, the Exchange requires participants to exceed minimum requirements for financial integrity. Participants must contribute to the NYMEX Guaranty Fund which acts as a safety net to assure the performance of the contract. The Exchange limits the value of the futures "positions" a participant may hold, and limits the number of contracts it may hold. Holders of futures contracts must maintain deposits, called "margins." Margins increase as the given contract nears delivery. In short, through these restrictions and through the standardized terms of the futures contract, NYMEX assures that the only risk a participant faces is the risk of price change. In dramatic contrast, a lessee selling in the lease market faces the risks that its wells will not produce (because of accidents, equipment failures, and the like), risks that it will incur unexpected costs, and risks that its purchaser will be unable to perform for a variety of reasons. These are in addition to the risk of price change with which a lessee must contend. The assurances NYMEX provides frequently give the paper barrel a premium value over the wet barrel sold in riskier transactions in the wet barrel market.

In sum, IPAA objects to the use of a NYMEX based price to value oil at the lease because of differences in:

- **Commodities Traded:** NYMEX trades contract rights; the lease market trades barrels of oil.

- **Timing:** NYMEX prices value oil at least one month earlier than the month of production; the lease market values oil during the month of production.

- **Location:** NYMEX values oil delivered in Cushing, Oklahoma, and MMS will have to make price adjustments it admits will be difficult -- and which will require a massive new federal data collection and digestion effort -- to approximate values at the lease; the lease market values oil at or near the lease already.

- **Risk:** The NYMEX contract has only one of the many risks the wet barrel sales contract has, and essentially no risk of non-performance. The NYMEX price therefore commands a premium.

In sum, MMS's proposal is flawed. That flaw is underscored by MMS's reasoning for using the ANS price instead of the NYMEX price for leases in California and

Alaska. Both the NYMEX price and the ANS price are based on deliveries of oil at central market locations, ordinarily far from the lease where the oil was produced. To its credit, MMS admits that the "most difficult problem ... would be to make appropriate location and quality adjustments when comparing the NYMEX crude with the crude produced." 62 Fed. Reg. 3745. In fact, MMS admits the problem is so great that it prevents it from applying the NYMEX price to production in California and Alaska. It uses ANS as a proxy because it is "a more localized market indicator" which would "better represent royalty value." *Id.*

MMS's solution here does not go far enough. Given the Department's longstanding and sound conviction that the market transaction closest to the given well best reflects lease value, the Department needs to return to the even "more localized market indicator[s]" it has relied on in the past: a lessee's gross proceeds from sales to unaffiliated parties and comparable sales in the lease market.

Problems with MMS's Proposed Adjustments

Jack Blomstrom's testimony at the Denver hearing provides the perfect introduction to the enormous difficulties MMS faces if it attempts to administer a NYMEX-based scheme for valuing oil at the lease. Responding to MMS's illustration that Wyoming sour crude shipped to Salt Lake City would be valued by reference to West Texas sour crude, he observed that "it demonstrates a lack of market awareness by the MMS...."[8]

> [T]here is little, if any, similarity in West Texas (WT) Sour and Wyoming [(WY)] Sour other than the fact both contain sulfur. They are sold in totally different markets. WT Sour averages -- as I understand it from industry information, 1.9% sulfur. WY Sour is classified as either Wyoming General Sour or Wyoming Asphaltic Sour. The General Sour has gravity of from 22 [degrees] to 28 [degrees]. That represents a mid-point of 25.5 [degrees]. The Asphaltic Sour which represents the overwhelming percentage of Wyoming Sour production is 20 [degrees] to 22 [degrees]. The gravity differential alone, which is not considered in this example at all, between WT Sour and WY Asphaltic would be $2.40/bbl. It would seem that if the MMS values its royalty oil without factoring in the gravity differential, it will receive a windfall....

[8] In its haste to publish its proposal, MMS overlooked that no Wyoming sour crude oil is shipped to Salt Lake City.

(Exhibit 3.) Not unlike the market area west of the Rockies, the Rocky Mountain area is an isolated market. And, as elsewhere, prices actually negotiated in the Rocky Mountain area are heavily influenced by local supply and the demand from local refineries.

More generally, IPAA's concerns with the adjustments are both legal and practical. First, we are unaware of any statutory authority for proposed 30 C.F.R. § 206.105(d)(3), 62 Fed. Reg. 3755, which would require each lessee to file Form MMS-4415 for each buy/sell agreement, exchange agreement, or "sale subject to balancing" in which the lessee or its affiliate engaged in, whether involving federal, state, or private lease oil, and without regard to where the exchange occurred in the stream of commerce.[9] Many of these transactions will be conducted by companies beyond the point of first sale or royalty computation for oil produced from federal leases. Section 103 of FOGRMA limits the Secretary's power to compel the creation and submission of documents to those pertinent to oil from federal and Indian leases through the point of first sale or royalty computation, whichever is later. He has no power respecting oil produced on private or state leases. 30 U.S.C. § 1713(a).

Furthermore, as a practical matter, the adjustments are likely to produce distortions in the value of the crude oil as MMS works upstream from Cushing to the thousands of producing federal leases. As explained earlier, by adjusting back from market centers, MMS captures royalty on the value added by aggregating large volumes of oil and selling them on the spot market. This value is in addition to the value added merely by the transportation of the oil. Yet this value does not exist at the lease where royalties are to be computed. There is the potential here for the taking of valuable rights under the lease contract.

Special problems exist when a lessee sells at the lease. It does not have the information needed to adjust for transportation costs from its lease to the aggregation point. Its purchaser is unlikely to respond to inquiries about the purchaser's cost of transportation. The same lessee will not have the information needed to adjust for quality and location differences between the aggregation point and the market center.

MMS's solution to the lack of transportation data is simply to leave the lessee stranded. The proposed rule calls this deduction of transportation costs "optional." Proposed 30 C.F.R. § 206.105(c), 62 Fed. Reg. 3754. This "solution" is simply a demand for royalty on the value added by the movement of the oil down the stream of commerce, for royalty on phantom proceeds.

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[9] The proposed rule does not disclose, when a lessee is making the initial submission of these forms, how far back in time the lessee must review its records to report. 62 Fed. Reg. 3755.

Concerning the lack of information about exchanges, the proposed rule is more charitable. MMS proposes to compute its own number for lessees to use. But the data will be one to two years out of date, and MMS's number will be untestable because it is based on confidential business information. MMS's number will not reflect the current market value of exchanges between aggregation points and market centers.

Finally, MMS's consultants believe that MMS can reliably value all crude oil east of the Rockies by referring to Platt's index prices for West Texas Intermediate, West Texas Sour, Louisiana Light Sweet, Louisiana Heavy Sweet, and Wyoming Sweet. It is debatable whether Platt's accurately reflects trade differentials on a given day, but putting that concern aside, many of the volumes on which its prices are based are nominal. Guernsey, Wyoming, for example, does not have enough volume sold to establish a reliable value for a differential governing all crude oil transactions. At other locations, other problems exist. First, much of the crude that is traded is done during a one-week period. The daily arithmetic average of a Platt's differential would not accurately reflect the true trade differential for the bulk of the crude. Second, while Platt's might reasonably portray how the market is moving for spot sales, it ignores transactions in the term market. Third, it will be very difficult to compare the few crudes reported in Platt's to the variety of crudes traded. Koch's posted price bulletin has 49 different crude types. It is particularly hard, for example, to compare the value of West Texas sour crude to sour crudes in the Rockies or in the Southeastern United States.

The OCS provides another example where the proposed NYMEX price methodology does not accurately reflect market value at the lease. In January 1996, a member lessee's arm's-length sale netted $12.62 per barrel. Using MMS's proposed rule, the value would have been $16.13, a $3.51 difference. A chief cause for the discrepancy is MMS's failure to adjust for quality between the lease and the aggregation point. In this example, the gravity at the lease is significantly lower than the common stream at the aggregation point. The quality bank adjustment for that month was $3.21. This still leaves a difference of $0.30 below the MMS proposed value. Information from subsequent months bear this point out. Even if MMS makes quality adjustments to the NYMEX price, there can be substantial unexplained differences, both higher and lower, from the market value of an arm's-length sale at the lease.

In sum, MMS has proposed these adjustments in an effort to bring certainty to royalty valuation. But the only thing a lessee can be certain of about these adjustments is that they will be wrong.

ALTERNATIVE: MMS SHOULD TAKE ITS ROYALTY IN KIND

While IPAA's position on this proposed rule has little in common with the views of MMS's consultants, there is one paramount point on which all agree. One MMS consultant said it well. "The only way to be absolutely certain that a fair market value is received for royalty oil is to take the oil in kind for sale" by MMS. (Exhibit 20 at 11.)

IPAA supports MMS's exploration of ways to market its royalty share of production. IPAA has actively supported MMS's pilot project for taking natural gas royalties in kind. Larry Nichols of Devon Energy testified in June 1996 before the House of Representatives' Subcommittee on Energy and Mineral Resources in support of the pilot project as the best means toward the end of eliminating disputes between MMS and lessees over the value of production. "When taken in-kind, market value is the price that the MMS receives from the willing purchasers." (Exhibit 21 at 4.)

That goal is more readily achievable for royalty oil. MMS has had long experience in selling royalty oil in kind and currently sells almost 40 percent of its oil royalty. IPAA strongly endorses MMS's current initiative studying the option of marketing all its own royalty oil.

By taking oil in kind, MMS will gain three benefits. It will bring to an end its valuation controversies with lessees. It will have a better basis to judge whether following a pricing scheme like the one it would impose on lessees through this proposed rulemaking makes any business sense. And if such a scheme proves to make sense, MMS will, having taken the risks of the marketplace, earn the higher rewards that the market holds for successful risk-takers.

Except for certain marginal and isolated properties with production too small to be worth the administrative cost, MMS's commitment to royalty in kind should be total. For these properties, such as isolated stripper well properties, MMS would take royalty in value using the lessee's gross proceeds or, if the sale is not at arm's length, the nearest applicable posted price.

As Gary McGee of Devon Energy testified at the Casper workshop on royalty in kind (Exhibit 22), the procedure need not be complicated. MMS would take its royalty in barrels delivered at the point already established by the Bureau of Land Management onshore, or MMS offshore, for the measurement of volumes for royalty purposes. For OCS leases, the lessee is to deliver the oil free of cost to the lessor "on or immediately adjacent to the leased area...." Under more recent lease forms, MMS has the option of requiring the lessee to provide delivery of the oil "at a more convenient point closer to shore or on shore," provided that MMS reimburse the lessee for the cost of transportation to that point. Under the older lease forms, that option is the lessee's. Compare Form MMS-2005 (March 1986) § 6(c) with Form 3380-1 (February 1966) § 2(a)(3). For consistency's sake, MMS should take all royalty in kind on the lease. The lessee's sole obligation would be to deliver the correct number of barrels in a physical condition acceptable under contracts typical for the field. Taking control of the oil at the lease will alleviate complications that would arise from reimbursements for transportation and balancing.

MMS could then contract with a small number of companies with production and marketing experience to take the oil at that point for sale at a market center. These companies would act as MMS's marketing agents, would sell the oil for the best possible price, and would pay MMS for its barrels at the sales price minus transportation costs and a negotiated marketing fee. Using its agents in this way, MMS could avoid downstream risks of environmental liability, but still hope to profit from taking the risk of price changes in the downstream markets and from adding value to its volumes by aggregating them. The payment of the marketing fee would transfer much of the administration of the downstream risks to the agents, further simplifying the federal role. MMS should give lessees six months of lead time before taking royalty in kind, and it should give its marketers the security of a two-year contract.

MMS could achieve dramatic administrative cost savings over its current system of royalty in value. The Province of Alberta, Canada, currently employs only 33 people to run a royalty in kind program which sells 146,000 barrels of oil per day. The Royalty Management Program, MMS, employs (we estimate) 528 people to assure that the proper value is paid on about 205,000 barrels per day. The agency could dramatically reduce the size of its workforce and -- if the premises of this proposed rulemaking are correct -- significantly increase its return on royalty oil. Additional details on the Alberta program and on the administrative efficiencies it has achieved are found in the testimony of Sue Hamm of Continental Resources, Inc., at the Houston hearing. (Transcript at 137-48.)

MMS already has the necessary statutory authority to institute a program like Alberta's. For onshore leases, it authority comes from section 36 of the Mineral Leasing Act, 30 U.S.C. § 192. Section 36 permits the Secretary to sell crude oil "upon notice and advertisement on sealed bids or at public auction...." *Id.* If he receives no acceptable bid, he may sell the oil "at private sale at not less than the market price...." Generally, of course, the Department has limited its sales of onshore royalty in kind to "refineries not having their own source of supply for crude oil...." *Id.* If the Department continues to find that "sufficient supplies of crude oil are not available in the open market to such refineries," it may grant these refineries a preference and offer them oil "at private sale at not less than the market price...." *Id.* Nothing in the statute requires the Department to offer this oil for sale at the wellhead, nothing sets a price cap on what the Department may charge, and nothing prevents the Department from selling whatever oil independent refiners do not require on the open market.

For the OCS, the authority is similar. The Secretary may sell royalty oil "by competitive bidding for ... not less than its fair market value...." 43 U.S.C. § 1353(b)(1). Like the onshore statute, the offshore statute grants a preference for "small refiners." 43 U.S.C. § 1353(b)(2). If the Secretary determines that "small refiners do not have access to adequate supplies of oil at equitable prices," he may allocate oil among them by lottery or otherwise. The price in sales to small refiners is capped at the "fair market value," *id.*, a term defined by Congress. 43 U.S.C. § 1331(o). But the Secretary may sell quantities in excess of the needs of small refiners for at least the fair market value of the oil. As is the case onshore, the statute does not require the Department to deliver the oil at the wellhead; it may sell it for at least fair market value downstream.

ASSOCIATED CONCERNS

ROYALTIES ON BUYDOWNS

Proposed § 206.102(a)(5), 62 Fed. Reg. 3753, claims that a lessee's gross proceeds "include payments made to reduce or buy down the purchase price of oil to be produced in later periods." To the extent that the payments in question are to compensate the lessee for waiving rights under an existing contract, this position violates *IPAA v. Babbitt*, 92 F.3d 1248 (D.C. Cir. 1996).

In that case, the Department of Justice in its brief to the court vigorously argued that buydowns were subject to royalty and that buyouts and settlements of accrued take-or-pay liability were functionally no different.[10] In so doing, the Justice Department simply followed the position taken by Assistant Secretary Deer in *Samedan Oil Corp.*, MMS-94-0003-IND (Sept. 16, 1994), who reasoned that all three were indistinguishable: all were payments in anticipation of the lessee receiving a lower price in post-settlement sales of production. Slip Opinion at 12-13, 16 n.10, and 17.

The Department's views on buydowns were therefore squarely before the Court. That the Court addressed those views could not be clearer.

> The take-or-pay settlements were of two types -- "**buydowns**" and "buyouts." In a **buydown**, the pipeline pays a cash lump sum to the producer in exchange for contract amendments (or a new contract) providing for continued sale of the contracted-for gas at reduced prices. In a buyout, the pipeline pays a cash lump sum in exchange for release of the pipeline from the gas purchase contract. . . . Both types of contracts also often include a settlement of existing liability for previously incurred take-or-pay obligation.

92 F.2d at 1252 (boldface added). The Department litigated the issue of buydowns, and it lost. The Court rejected the Department's arguments as to both buydowns and buyouts, finding them indistinguishable under the gross proceeds rule.

> Take-or-pay payments and contract settlement payments are functionally indistinguishable with respect to the calculation of royalties. Both types of payments satisfy outstanding take-or-

[10]Please refer to pages 7, 8, 10-11, 13-14, 15, 23-24, 26-28, 30, 39-41, 42-44 of the Brief of the Federal Appellees, and all of Appellees' Petition for Rehearing, in which the Department urged affirmance of its position on buydowns and failed to draw any distinction between buydowns and other forms of take-or-pay settlements.

> pay obligations, and both types can be recoupable or nonrecoupable. The only difference is whether the payments follow negotiations between the parties over the cancellation of contractual obligations. We see no way in which the occurrence of these negotiations changes the functional nature of the payments for royalty purposes. The relevant question in both cases, under *Diamond Shamrock*, is whether or not the funds making up the payment actually pay for any gas severed from the ground. When take-or-pay payments (or settlement payments) are recouped, those funds do pay for severed gas. But when the payments (of either variety) are nonrecoupable, the funds are never linked to any severed gas. Therefore, no royalties accrue on those payments.

Id. at 1260 (footnote omitted). Like the Department of the Interior and the Department of Justice, the Court of Appeals saw no distinction between buyouts and buydowns.

To the extent there is no prior contract between the parties to be settled by the payment, our members are unaware of any instance, let alone custom, in the industry under which a purchaser has offered or would offer an up-front lump sum payment coupled with a below-market price for the oil.

<u>FERC APPROVED TARIFFS AS TRANSPORTATION ALLOWANCES</u>

Proposed § 206.105, 62 Fed. Reg. 3754, would prevent lessees from relying on FERC approved tariffs whenever it ships oil through a pipeline in which it owns a sufficient interest for it to be deemed in "control" of the pipeline. The rationale for the change is that "FERC ruled that it lacks jurisdiction to enforce the Interstate Commerce Act with respect to oil pipelines located wholly on the [OCS]. See *Oxy Pipeline, Inc.*, 61 FERC ¶ 61,051 (1992) and Bonito Pipe Line Company, 61 FERC ¶ 61,050 (1992)." 62 Fed. Reg. 3746. The position of the MMS, as stated in the Orders and the Field Report, is that the FERC renounced jurisdiction over oil pipeline transportation on the OCS in deciding the *Oxy* case. That is a misstatement of what the FERC decided. The FERC has not renounced jurisdiction over oil pipelines transporting on the OCS. Rather, in deciding *Oxy*, the FERC applied the existing legal precedent to the specific facts presented by *Oxy*.

Since the beginning of this century, the law of the United States has been that the transportation of crude oil by pipeline, whether onshore or offshore, is subject to the Interstate Commerce Act ("ICA") if it is part of a chain of transportation that, viewed in its entirety, is interstate in nature. Thus, the ICA imposes jurisdiction over the transportation of crude oil by pipelines in certain situations and the determining factor is not whether such transportation is offshore or onshore, but whether or not it is in interstate commerce. The courts and FERC have also held that in determining the essential character of commerce, the most important factor is the transportation intent of the shipper at the time of shipment.

In support of its argument that its transportation was not jurisdictional, Oxy Pipeline averred that "its pipelines cross no state lines, that it 'has no knowledge of the ultimate destination of the oil,' and that no non-owner of the pipelines has ever expressed an interest in shipping oil over the pipelines." *Oxy*, 61 FERC at 61,226 - 61,227. Applying the standards established by the U.S. Supreme Court, it is obvious that the "transportation intent of the shipper" was to transport oil from one point to another on the OCS with no knowledge of the ultimate destination and therefore no intent for the transportation to be a link in a chain of transportation in interstate commerce. The FERC thus determined that based on the facts presented, Oxy's transportation was "solely" on or across the OCS, not in interstate commerce and, therefore, not subject to the jurisdiction of the ICA.

It is essential to recognize, however, that the FERC also held that the transportation would be subject to ICA jurisdiction if "the facilities [the chain of transportation] exited the OCS and the oil moved in interstate commerce." *Id.* at 61,227. (bracketed comment added). Moreover, a footnote to the opinion stated that:

> A pipeline that starts on the outer Continental Shelf and transports oil through the seaward boundaries of the States to shore for further movement, in interstate commerce is jurisdictional under the ICA.

Id. at 61,228, footnote 14. This position, which is essentially a restatement of the law as interpreted by the Supreme Court, was restated by FERC Chair Mohler in a letter to the Acting Director of the MMS ("Mohler Letter"). Chair Mohler provided the following example:

> if a shipment commenced offshore, moved through Pipeline A to a point in a state adjacent to the OCS, and then moved through Pipeline B to a point in another state,... the intent of the shipper to ship in interstate commerce to the point in the other state would show that the movements through Pipeline A and Pipeline B were merely links in an interstate chain of movements that would be subject to jurisdiction under the ICA. Thus, in making a jurisdictional determination, the essential character of the movement across state lines would be determinative that the movements through Pipeline A and Pipeline B were in interstate commerce,...

Mohler Letter at 1-2. In this example, although there is transportation of oil on or across the OCS, such transportation is subject to the jurisdiction of the ICA and the FERC because it is not "solely" on or across the OCS, but is a link in an interstate chain of movements that happens to include transportation on the OCS.

The FERC has not renounced jurisdiction over transportation of oil on the OCS, but has made it clear that the only oil transportation on the OCS that it has ever exercised jurisdiction over was transportation in interstate commerce. On January 18, 1997, the Director, MMS, rejected the view that FERC had disclaimed all jurisdiction over OCS pipelines. *Torch Operating Co.*, MMS-94-0655-OCS at 5 (1997). Therefore, the proposal to eliminate reliance on FERC tariffs is inconsistent with MMS's precedent.

CONCLUSION

MMS should continue to value arm's-length sales using a gross proceeds approach at the lease. If MMS continues to take royalty in value, it should value non-arm's-length sales under an improved benchmark system based on comparable arm's-length sales at or near the lease. This will assure MMS receipt of fair market value.

IPAA opposes the use of NYMEX/ANS prices to value non-arm's-length sales, opposes MMS's attempt to create a duty to market oil, and believes the most efficient solution to the economic waste of royalty value disputes is for MMS to sell its own royalty oil.

IPAA is grateful for this opportunity to comment and looks forward to continuing to work with MMS on these important issues.

Sincerely,

Denise A. Bode

Denise Bode
President